APPENDIX C

OIL REFINERIES

C-1   INTRODUCTION

Oil refineries have been shown in the past[1] to be major stationary sources of NOx in the South Coast Air Basin. However, estimates of the overall average emission factor for refinery gas/natural gas combustion have ranged from 0.16 lb NOx/MMB[31] to 0.28 lb NOx/MMB. The latter figure is based on measurement of the emissions from 63 refinery heaters and boilers burning refinery gas by the San Francisco Bay Area APCD.[51] The former figure is that used by the Los Angeles APCD to estimate refinery emissions in Los Angeles County.[31] The LAC APCD figures are apparently based on data obtained in the 1950's using wet chemical methods, possibly from a sample of units with a high proportion of natural draft with our preheater. The BA APCD data were obtained using chemiluminescent instruments. A wide range of modern refinery units were tested during 1972 for that program.

Because of the large uncertainty associated with those two figures, as discussed in Section 7.0, it was decided to concentrate a substantial portion of the test program on refinery combustion devices.

In order to pursue this objective, the cooperation of the seven major refineries in the South Coast Air Basin was obtained. All tests were performed on a voluntary basis. In two refineries independent measurements were made of NO emissions by refinery personnel concurrent with KVB measurements.

The predominant fuel consumed in refineries is refinery gas. The distribution of fuels for FY '72 is about 72% refinery gas, 22% natural gas and 6% oil. During the summer months the fuel is almost entirely a mixture of refinery gas and natural gas while in the winter about 17% of the fuel is oil. Refinery gas composition varies widely from heater to heater within a refinery. Heating values may range from less than 800 Btu/scf to over 1900 Btu/scf Although no systematic experimental program has been reported, it would be expected that NOx production would be higher for gas compositions producing higher heating values, since this effect is due to the presence of heavier hydrocarbons with higher flame temperatures. Because of the predominant use of refinery gas and because of the major uncertainties in NOx emissions from

its combustion, major emphasis was given to testing units operating with this fuel.

The units tested were selected to include a representative sample of current refinery heaters and boilers. Where possible larger units representing major NOx sources were included. Table C-I summarizes the combustion devices tested. As can be seen, a range of heat input and device type was selected. Requests to test specific selected units were honored by the refinery for the most part. The total number of process steam boilers tested was larger than the initial plan because of substitutions (when the desired type of heater was out of service) and because identical units operating side by side were compared in some cases.

Within each class of combustion device several variations were tested. Forced draft, natural draft, vertical or horizontal burner orientation, high or low heat release, hot or cold refractory, number of burners, heating surface arrangement, burner type, and the presence or absence of air preheaters were included in the test sample. Of course, independent variations of these parameters were not possible, since several configurational and geometric differences occurred from unit to unit.

Information obtained from one oil company suggests that 60-70% of the fuel is consumed in heaters. The test sample fuel distribution was 55% for heaters, 29% for process boilers and 16% for CO boilers.

Table C-I

SUMMARY OF REFINERY UNITS TESTED

Combustion Device	Heat Input (MMB/h)	No. Tested
Crude Heaters	60-394	11
Process Heaters	16-365	16
Process Steam Boilers	14-397	15
CO Waste Heat Boilers	61-521	4
Coker Heaters	58-241	3

Continuous on-line sampling of the exhaust gases were accomplished
with the instrumentation and procedures described in Section 8.3 and 8.4.
This enabled a determination of effects of variables such as changes in
fuel gas composition, process rates, and firing rates. Unfortunately,
simultaneous (rather than independent) variations of these variables occurred
over very short periods of time. Fuel gas samples were obtained and analyzed
for most tests (either by KVB, the refinery, or both). However, attempts to
relate NOx to gas composition are limited by the necessity to assume that
the single sample is representative for the entire test period.

A total of 49 heaters and boilers were tested out of a total inventory
of about 350. Those devices tested accounted for about 30% of the total refinery
fuel consumption in the Basin. On the basis of the devices tested, a correla-
tion was established for emissions of NOx for refinery heaters and boilers.
Attempts to correlate the data to account for differences in fuel gas com-
position were only partially successful. Although large changes in NO emis-
sions were measured as gas composition changed, a sufficient number of gas
analyses could not be obtained to establish a firm correlation. The final
NOx inventory compilation was calculated based on averaging the results for
different gas compositions.

Because of differences in the reported average operating conditions
from the specific test conditions the test results for an individual unit were
not used for that specific unit in the final inventory. Instead the correla-
tions developed from the test data were applied to all heaters and boilers.

Estimates of the NOx reduction possibilities were based on the previous
experience of KVB with power plant and industrial combustion devices.
Differences that are unique to refinery operation are fuel gas composition,
high capacity factors, heater configuration, and heat transfer conditions.

MEASUREMENT OF NOx EMISSIONS FROM REFINERY SOURCES

The basic test procedure and instrumentation used during the test program are discussed in Section 8.0. For refineries, the operating mode and accessibility of the combustion device were paramount in determining the test plan for each unit. Probes were inserted through existing sampling ports, usually located upstream of the air preheater if there was one. The most desirable test plan was to make measurements at several probe locations in the exhaust gas ducting at a constant set of operating parameters; then, repeat for a variation of the important parameters (such as heat input, excess air, air register setting, etc.) in a controlled manner. However, testing of refinery devices showed that the steady state conditions necessary to separate spatial and temporal effects or to arrive at an accurate difference reading for NO_2 are usually not present. Test data were recorded continuously, but was only read off for data reduction purposes during periods of steady operation of the order of 5 to 10 minuets. When fuel changes resulted in major shifts, additional data were taken at the new quasi steady state point. In addition, in some cases existing, unheated instrument lines were used for the sample, eliminating the possibility of a wet NO or NOx measurement. Moreover, because of the interdependence of various devices in the refinery practically no controlled variation of combustion parameters was possible.

In the refinery tests, samples of the fuel gas and fuel oil were taken during the period when measurements are made so that chemical composition and heating value information could be obtained. Large, short term variations in both parameters for fuel gas were typical of conditions found. For example, during Test 47 the fuel gas heating value decreased from 1528 Btu/scf to 1421 Btu/scf over a 15-20 second period. As can be seen, the NO concentration was decreased by 50%.

The accuracy of the results can perhaps be evaluated best by comparing KVB measurements with those obtained simultaneously by two refineries using completely different test instruments. These data are summarized in Table C-II. For a total of 17 comparative tests on 11 different devices, the average difference of the KVB measurements and refinery measurements was 2.4%.

TABLE C-11

COMPARISON OF KVB AND REFINERY MEASUREMENTS

| Refinery | KVB MEASUREMENTS | | REFINERY MEASUREMENTS | | % DIFFERENCE |
	NO	NO @ 3% O_2	NO	NO @ 3% O_2	KVB-refinery refinery
"A"		285-302		290-305	-1.3
"A"		211-267		228-258	-1.6
"A"		116-143		100-137	+9.3
"B"	44		43-50		-5.4
"B"	22-32		38		-29.0
"B"	109		100-102		+7.9
"B"	28-48		33-36		+10.1
"B"	460-490		450		+5.6
"B"	400		440		-9.1
"B"	420		440		-4.5
"B"	460		450		+2.2
"B"	320		375		-14.7
"B"	380-400		390		0
"B"	630		610		+3.3
"B"	75-80		90		-13.9
"B"	86		92		-6.5
"B"	64		60		+6.7

5800-179

As a further confirmation of the accuracy of the results, the NO calibration gas utilized by one refinery was measured by KVB. The calibration gas was certified by the manufacturer to be 202 ppm. The KVB measurement was 200 ppm.

The averaged results of all refinery combustion devices tested are summarized in Table C-III.

These values were obtained by averaging the test points taken over a 2-3 hour test period. In some cases large variations were measured as gas composition or other variables changed. For example, the heater of Test 25, which had an average emission factor of 1.01 lb NOx/MMB, had values ranging from .76 to 1.28. The heater of Tests 31-34 which had an average of .46 lb NOx/MMB showed values ranging from .33 to .81. (All test data are presented in Appendix B). Thus, characterization of "typical" emissions from any given heater is very difficult because of the inability to characterize its typical fuel or operation mode. Instead, the approach was taken to use averaged data (and correlations) obtained for many tests.

The relations used to convert the nitrogen oxides concentration at 3% oxygen to weight flow of nitrogen oxides as NO_2 are summarized in Table C-IV. The fuel mass flow was obtained by measurement or calculation from the process heat rate and fuel heating value. The value for E for each test was determined by analysis of the fuel gas composition either by gas chromatograph or mass spectometer. In some cases results of an independent test laboratory were used; in other cases results of the refinery laboratory were used. Where a conflict existed, the refinery results were used. Examples of two typical refinery gas analyses, showing the wide variations possible are given in Table C-V. In the few cases where fuel gas or oil flow rate was not available, the heat input was taken to be the process heat input divided by an assumed efficiency of 0.85. One refinery suggested 70-75% was a more representative efficiency value. However, this would result in higher total emissions and the same emission factors.

The total NOx as NO_2 measured for the 49 units (some tests in Table C-III are on the same unit) was about 2087 lb/hr (25 tons/day) for a total heat input of 7329 MMB/hr. These totals are significant in that these units account

TABLE O-III

SUMMARY OF REFINERY TESTS

KVB Test No.	Unit	Rating MMB/H	No. of Burners & Position	Fuel	Fuel Gas Heating Val. & H/C Atom Ratio, BTU/scf	Heat Input MMB/H	Flue Gas Oxygen %	Carbon Monoxide ppm	Nitrogen Oxide NO @ 3% O_2 ppm	Emission Rate lb NO_2/hr	Emission Factor lb/NO_2/MMBTU	Comments
12	Process Steam Boiler	400	6H	F.G.& Oil	1663-2.98	397	4.6	5	290(W)	145	.364	FD,Burning Oil Droplets impinging on firebox. 550°F air.
13	Carbon Monoxide Boiler	450	9H	F.G.& CO	857-4.58	506	1.3	0	138(W)	217	.58*	1145°F CO Temperature.
14	(Same as 13)	450	9H	F.G.& CO	857-4.58	521	1.0	5	126(W)	197	.53*	
15	Process Steam Boiler	250	6H	Oil		342	4.4	4	282(W)	124	.362	BD Burning Oil Droplets impinging on Firebox wall
16	(Same as 15)	250	6H	F.G.& Oil	1663-3.33	320	5.4	3	297(W)	119	.378	380°F air temperature
17	(Same as 15)	250	6H	F.G.& Oil	1663-3.33	369	5.1	5	288(W)	133	.368	
18	(Same as 15)	250	6H	F.G.& Oil	1663-3.33	301	2.6	32	245(W)	72.4	.313	
20	Process Heater	106	50H	F.G.	752-5.45	74	4.2	0-310	86(W)	7.1	.096	ND
23	Crude Heater	125	12V	Oil		60	4.5	4	138(W)	10.6	.177	ND
24	Process Heater	80	12D	F.G.	1732-3.05	62	6.8	4	333(W)	25.3	.405	ID,very hot (orange) region around burners. 630°F Air
25	Process Heater	80	12D	F.G.	1104-3.65	39	5.4	0	797(W)	39.8	1.01	ID,extremely hot(yellow-orange)region around burners. 630°F air temp.
31 -34	(Same as 24)	80	12D	F.G.	1428-3.23	55	5.0	0->2000	326(W)	23.8	.463	Same as 24 except air leak around burners sealed,620°F air temp.
35	Process Steam Boiler	118	2H	F.G.& Oil	1423-3.28	53	7.3	5-15	104(W)	6.6	.128	FD
36	Process Steam Boiler	118	2H	F.G.& Oil	1423-3.28	64	4.0	3-5	103(W)	8.1	.127*	FD
37	Carbon Monoxide Boiler		4H	F.G.(tr) & CO	1423-3.28	61	3.8	10	160(W)	42.7	.70	1230°F CO Temperature
38	Crude Heater	150	10V	F.G. & Oil	1423-3.28	82	5.4	0	137(W)	14.3	.173	ID,545°F Air Temp.
39	Heat Medium Heater	190	24H	F.G.& Oil	808-4.84	97	5.8	0	250(d)	11.2	.305	ND,extremely hot refractory(yellow) in spots. Variability of flames.
40	Process Steam Boiler	220	4H	Oil	-	99	6.6	0	296(d)	37.9	.400	BD
41	Process Steam Boiler	83	4H	F.G.	808-4.84	44.8	10.5	0	231(d)	12.5	.273	FD, Heavy deposits
41a	(Same as 41)	83	4H	F.G.	808-4.84	34.8	8.5	448	108(d)	4.5	.120*	FD,large CO concentration

LEGEND: ND – Natural Draft   D – Downward
         FD – Forced Draft   w – Wet
         BD – Balanced Draft d – Dry
         H – Horizontal   FG – Fuel Gas
         V – Vertical

5800-179

C-7

TABLE C-III

SUMMARY OF REFINERY TESTS

KVB Test No.	Unit	Rating MMB/H	No. of Burners & Position	Fuel	Fuel Gas Heating Val. &H/C Atom Ratio, BTU/scf	Heat Input MMB/H	Flue Gas Oxygen %	Carbon Monoxide ppm	Nitrogen Oxide NO @ 3% O_2 ppm	Emission Rate lb NO_2/hr	Emission Factor lb NO_2/MMBTU	Comments
42	Process Steam Boiler	83	4H	F.G.	808-4.84	37.8	7.9	0	239(d)	7.8	.207	FD
43	Process Steam Boiler	83	4H	F.G.	808-4.84	34.4	12.0	0	180(d)	8.0	.224	FD
44	Process Heater(Coker)	126	32V	F.G.	1037-3.91	58	5.7	0	126(d)	10.5	.148	ND
45	Process Heater(Flasher)	122	32V	F.G.& oil	1187-3.58	109	2.9	0	207(d)	27.5	.257	ND
46	Process Heater(Flasher)	122	32V	F.G.& Oil	1187-3.58	109	3.1	450-800	166(d)	25.4	.237	ND, poor air register adjustment. High CO.
47	Crude Heater	205	48H	F.G.	1528-3.03	236	6.1	200-800	53(d)	15.3	.065	ND, extreme variability in flames. Burners in very poor condition.
47a	(same as 47)	205	48H	F.G.	1421-3.15	228	5.7	820	26(d)	7.1	.031	Same comments as (47)
48	Crude Heater	205	48H	F.G.	1373-3.16	180	4.6	0	120(d)	26.0	.144	FD,622°F air temp. Flame Variability.
49	Crude Heater	94	14H	F.G.	1181-3.52	105	2.0	170-600	32(d)	4.1	.040	BD, 610°F Air Temp.
50, 50a	Process Steam Boiler	187	4H	F.G.	1713-2.87	194	3.0	0	410(d)	97.8	.504	BD, 610°F Air Temp.
50b	(same as 50)	187	4H	F.G.	1713-2.87	125	3.3	0	305(d)	46.8	.375	Load Variation
50c	(same as 50)	187	4H	F.G.	1713-2.87	150	2.9	15	403(d)	74.2	.495	Load Variation
50d	(same as 50)	187	4H	F.G.	1713-2.87	158	3.0	0	420(d)	81.7	.516	Load Variation
50e	(same as 50)	187	4H	F.G.	1713-2.87	208	2.8	0	529(d)	135.5	.651	Load Variation
51	(same as 50)	187	4H	F.G.	1589-3.04	187	3.0	10	400(d)	91.4	.489	Excess Air Variation
51a	(same as 50)	187	4H	F.G.	1589-3.04	187	4.0	0	492(d)	112.2	.600	Excess Air Variation
51c, 51d	(same as 50)	187	4H	F.G.	1589-3.04	187	5.4	0	485(d)	110.1	.590	Excess Air Variation
52	Process Steam Boiler	177	7H	F.G.& oil (tr)	1615-2.98	199	4.8	0	356(d)	81.8	.449	BD, hot refractory (orange),552°F air Temp.
53	Process Steam Boiler	177	7H	F.G.& Oil (tr)	1588-3.00	212	4.6	25	724(d)	160.9	.898	BD,very hot refractory (whitish-yellow)550°F air
54, 55	Process Heater(Reboiler)	292	36H	F.G.	1046-3.91	167	2.9	0	77(d)	15.6	.093	ND,very uniform flame appearance
56	Crude Heater	29	4H	F.G.	1228-3.47	66	4.2/ 9.0	0	96(d)	7.4	.114	ND, large air leaks in brickwork.
57	Process Heater (Hydrogen Reformer)	300	608H	F.G.	1490-2.83	256	4.1	0	102(d)	34.9	.136	ND, very hot refractory around each burner.
58, 59	Process Heater (Reboiler)	-	14V	F.G.	1430-2.96	113	6.3	0	264(d)	39.5	.347	BS, 430°F
60	Process Steam Boiler	132	3H	F.G.	1590-2.83	150	1.2	>2000	272(d)	54.1	.358	BD,very high CO concentration, 430°F air

C-8
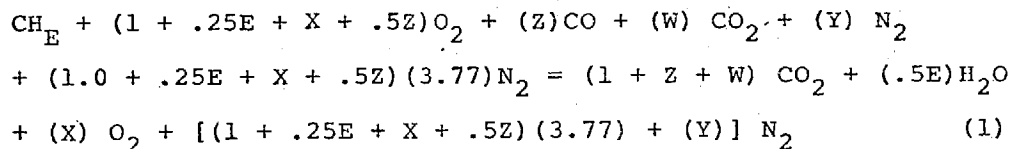
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TABLE C-III

SUMMARY OF REFINERY TESTS

KVB Test No.	Unit	Rating MMB/H	No. of Burners & Position	Fuel	Fuel Gas Heating Val. & H/C Atom Ratio,BTU/scf	Heat Input MMB/H	Flue Gas Oxygen %	Carbon Monoxide ppm	Nitrogen Oxide NO @ 3% O_2 ppm	Emission Rate lb NO_2/hr	Emission Factor lb NO_2/MMBTU	Comments
61	Process Steam Boiler	132	3H	F.G.& Oil	1590-2.83	119	7.9	0	182(d)	27.9	.236	B.D., Burning oil droplets impinging on firebox, 380°F air
62	Process Steam Boiler	132	3H	F.G.& Oil	1590-2.83	(250)	7.0	0	141(d)	(47.2)	.188	BD,380°F Air Temp.
63	Process Heater(Vac. Dist)	56	6V	F.G.	1590-2.83	62	13.0	0	104(d)	8.2	.133	ND
64	Process Heater (Reformer)	191	98H	F.G.	1590-2.83	312	5.5	0	122(d)	49.7	.159	ND,Hot Refractory (Orange)
65	Crude Heater	100	4H	F.G.	1359-3.28	74	14.0	0	152(d)	13.4	.182	BD,Amb.Air with Recirc. Flue Gas. 1150°F Flue Gas.
66, 67	Process Heater(Coker)	137	80V	F.G.	1032-4.06	130	5.2	0	249(d)	44.3	.341	BD
68	Crude Heater	252	36V	F.G.	1340-3.33	241	10.0	0	122(d)	35.19	.146	ND
69	Process Heater (Reboiler)	39	8V	F.G.	1340-3.33	16	15.0	290-380	95(d)	1.8	.114	ND, very erratic flame appearance
70	Process Heater (Reboiler)	47	3V	F.G.	1276-3.37	24	10.5	0	142(d)	4.1	.171	ND
71	Process Heater (Reboiler)	35	5V	F.G.	1276-3.37	18	5.0	0	122(d)	2.7	.149	ND
72	Carbon Monoxide Boiler	300	6H	F.G.& CO	1340-3.33	291	3.4	60	140(d)	101.1	.347*	FD,490°F Air Temp.
96	Crude Heater (Atmospheric)	355	60V	F.G.	1116-3.54	394	3.6	0	128(d)	62.1	.158	ND
97	Crude Heater(vacuum)	121	40V	F.G.& Oil	1144-3.40	141	3.2	0	129(d)	23.6	.168	ND
98	(Same as 97)	121	40V	F.G.& Oil	1156-3.34	114	7.0	10-20	87(d)	13.2	.116	ND,24 burners Oil, 16 on gas
99	Process Heater (Hydrocracker)	195	45H	F.G.	1156-3.34	153	3.2	0	67(d)	13.5	.088	ND
100	Process Heater (Hydrogen (Ref)	383	136H	F.G.	1135-3.37	365	5.2	0	136(d)	65.5	.179	ND
101	Process Steam Boiler	293	4G	F.G.& Oil	1241-3.17	224	4.4	0	200(c)	59.2	.264	FD
102	Carbon Monoxide Boiler	438		F.G. & CO	1241-3.17	321	3.8	40-90	178(d)	247	.81*	FD
103	Process Heater(Coker)	104	32V	F.G.	1279-3.10	68.2	5.2	0	84(d)	7.5	.110	ND

*Based on fuel consumption of CO plus fuel gas.
( ) Apparently incorrect control room instrumentation.

C-9

TABLE C-IV

COMBUSTION RELATIONS

The equation for combustion, including CO fuel, is

$$CH_E + (1 + .25E + X + .5Z)O_2 + (Z)CO + (W) CO_2 + (Y) N_2$$
$$+ (1.0 + .25E + X + .5Z)(3.77)N_2 = (1 + Z + W) CO_2 + (.5E)H_2O$$
$$+ (X) O_2 + [(1 + .25E + X + .5Z)(3.77) + (Y)] N_2 \qquad (1)$$

where E = hydrogen/carbon atom ratio in fuel gas

     X = ratio of percent O_2 to percent CO_2 in flue gas
        for no non-combustibles in fuel

     Z = relative percent of CO in fuel

     W = relative percent of CO_2 in fuel

     Y = relative percent of N_2 in fuel

The measured O_2 concentration $[O_2]$ under dry conditions can be expressed as:

$$[O_2] = \frac{100X}{4.77 + 2.89Z + W + Y + 4.77X + .94E} \qquad (2)$$

Solving for X gives:

$$X = \frac{[O_2]}{100-4.77[O_2]} \quad (4.77 + 2.89Z + W + Y + .94E) \qquad (3)$$

Using this value of X the weight flow of flue gas per unit weight of fuel is

$$\frac{\dot{m}_e}{\dot{m}_f} = \frac{(1+Z+W)(44.01)+(X)(32.00)+[(1+.25E+X+.5Z)(3.77)+Y](28.02)}{12.01+(E)(1.008)+Z(28.01)} \qquad (4)$$

The volume flow per unit weight (at standard conditions) is approximately:

$$\dot{V}_e/\dot{m}_f = \frac{(m_e/m_f)}{(.075)} \qquad (5)$$

The volume flow of NOx is:

$$\dot{V}_{NOx}/\dot{m}_f = C_2 \ \dot{V}_e/\dot{m}_f$$

    where C_2 = measured dry concentration of NO or NOx.

The weight flow expressed as NO_2 is:

$$\dot{m}_{NOx} = (46.01)(.002595)\dot{V}_{NOx}$$

TABLE C-V

TYPICAL REFINERY GAS ANALYSES

Test 47

Hydrogen	25.7%
Oxygen	0.2
Nitrogen	2.9
Carbon Dioxide	0.1
Methane	24.6
Ethylene	2.6
Ethane	8.7
Propene	9.2
Propane	14.2
i Butane	4.3
n Butane	6.8
i Pentane	0.4
n Pentane	0.3
Organic Nitrogen Compounds	None detected

Test 20

Hydrogen	62.6%
Oxygen	0.6
Nitrogen	3.2
Methane	23.8
Ethane	5.3
Propane	3.3
i Butane	0.4
n Butane	0.2
i Pentane	0.3
n Pentane	0.3
Organic Nitrogen Compounds	None detected

5800-179

for about 30% of the total heat input reported by the LA APCD refinery fuel use report for summer 1972.[31]

Figure C-1 is a plot of weight flow of NO_x as NO_2 versus unit heat input, for units operating only on refinery gas. Not included on this plot are CO boilers, oil or mixed fuel combustion, units with burners oriented vertically downward, and units with large amounts of CO (combustibles) during testing. The first three categories produce very high NOx emissions and if included on the plot would result in a higher average curve. Shown for comparison are the Bay Area APCD data[51] and the Los Angeles APCD curves for natural gas combustion[20] and refinery gas combustion. A large degree of scatter (although no more than similar plots by others) is apparent. (See discussion in Section 2.2.) Several subtrends are apparent in this plot. The balanced draft, horizontal burner units are generally higher than the others. The vertical natural draft units are closest to the mean while the horizontal natural draft units are usually much lower. By examining Table C-III it may be seen that these classifications are related to the presence (or absence) of air preheaters. The refinery gas data obtained on this program are mostly higher than the LAC APCD curve, particularly above a heat input of 70-80 MMB/H.

Some very high values of measured emission factors appeared to corre-late; (a) with extremely hot refractory adjacent to the burners, (b) with fewer burners, and (c) with high heating values for the fuel gas. The in-fluence of (a) and (c) on NOx production is in agreement with previously observed effects of adiabatic flame zones and of increasing flame temperature (See Section 2.1). The use of larger burners (and hence longer flames for similar flows) would appear to increase the residence time of combustion products at high temperature, resulting in a closer approach to equilibrium values of NOx concentration. Conversely, very low values appeared to occur for units which had numerous small burners and for units which were operating with a fuel gas of low heating value.

Correlation of the former effect and of the preheat resulted in the curve of Figure C-2, where emission factor [lb NO (as NO_2)/MMB] is plotted versus the heat release per burner. The main result shown in Figure C-2 is that much higher emissions result for forced draft units and units with preheaters. The correlations shown for those units and for natural draft units fall within ± 30% of most of the test data for refinery gas combustion. The exceptions
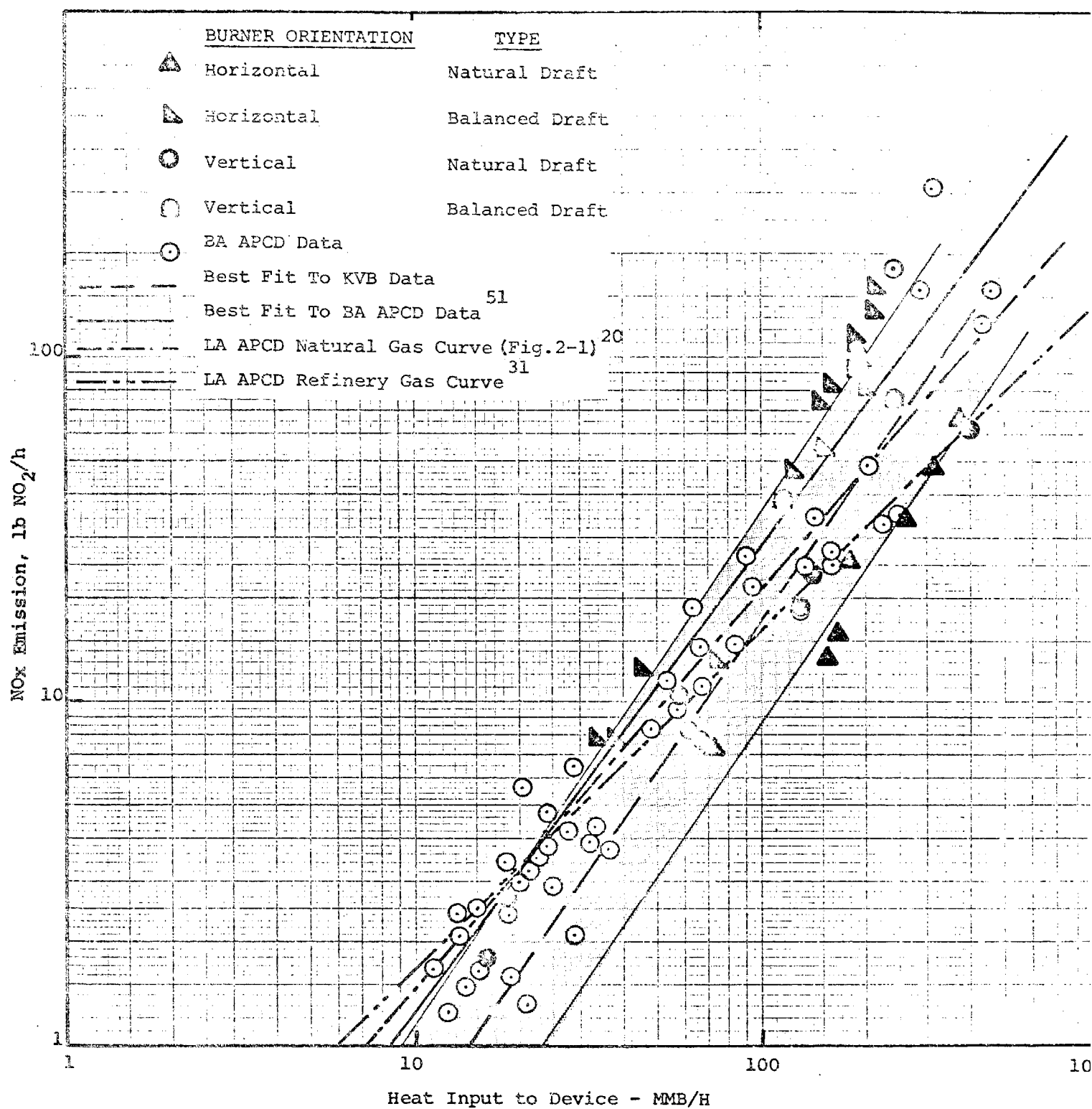
BURNER ORIENTATION | TYPE

Horizontal — Natural Draft

Horizontal — Balanced Draft

Vertical — Natural Draft

Vertical — Balanced Draft

BA APCD Data

Best Fit To KVB Data

Best Fit To BA APCD Data [51]

LA APCD Natural Gas Curve (Fig.2-1) [20]

LA APCD Refinery Gas Curve [31]

NOx Emission, lb NO_2/h

Heat Input to Device - MMB/H

Figure C-1. Total Emissions of Nitrogen Oxide for Refinery Heaters and Boilers Operating on Refinery Gas

5800-179
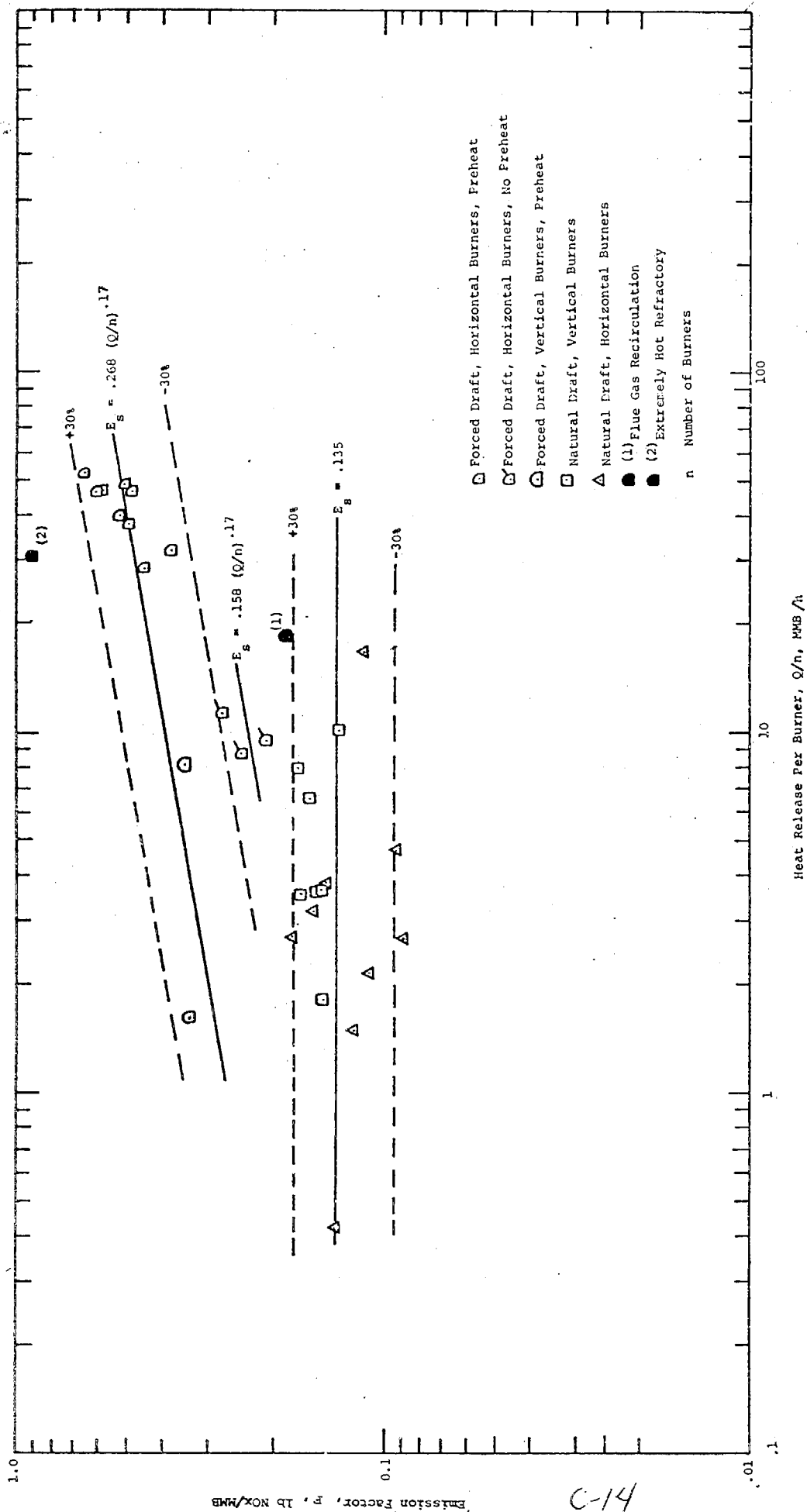
Figure C-2. Emission Factor for Heaters and Boilers with Refinery Gas Fuel.

$E_s = .268 (Q/n)^{.17}$

$E_s = .158 (Q/n)^{.17}$

$E_s = .135$

+30%   -30%

Heat Release Per Burner, Q/n, MMB/h

Emission Factor, F, lb NOx/MMB

Legend:
Forced Draft, Horizontal Burners, Preheat
Forced Draft, Horizontal Burners, No Preheat
Forced Draft, Vertical Burners, Preheat
Natural Draft, Vertical Burners
Natural Draft, Horizontal Burners
(1) Flue Gas Recirculation
(2) Extremely Hot Refractory
n Number of Burners

C-14

were units which had high NO emissions because of extremely hot refractory (Test No's. 24, 25, 31-34, 53) or which were low due to high CO levels or off-stoichiometric combustion (Test 41a, 46, 47, 47a, 49 and 60) or flue gas recirculation (Test 65). The low values of NO for the tests cited suggest these methods, off-stoichiometric combustion and flue gas recirculation, may be effective in reducing emissions from other heaters without interfering with normal operation.

In particular, the units of Tests 47, 48 and 49 were quite significant in that they were clearly operating in the off-stoichiometric mode (albeit unplanned). Refinery gas deposits had plugged the fuel passages of some burners. Visual inspection of the firebox showed that some burners were only passing air while the others were operating fuel rich in order to combust the required fuel at a reasonable overall excess air value. A generally hazy appearance in the firebox corresponded to visual observations characteristic of boilers which had been operated in a (controlled) off-stoichiometric mode. These heaters had been operated in this manner for at least several months over all the conditions unique to refinery operation with no apparent safety or operational difficulties. Shortly after testing, the units of Tests 47 and 48 were overhauled. It would be quite informative to retest these units to see if the NOx emissions are higher with all burners operating.

The number of units tested with oil or mixed fuel was not sufficient to generalize the results. Two effects were observed, however:

1. NO emission levels increased with fuel nitrogen. For Tests 35, 36, 38 and 98, oil with a nitrogen content of .019-.028 was the fuel. NO levels ranged from 87 to 137 ppm. Tests 12, 15, 23, 40, 45, and 46 were conducted during operation with fuel oil with a nitrogen content of .28-.46%. NO levels ranged from 138 to 297 ppm for those units.

2. Operation of a given unit with a higher ratio of oil to fuel gas produced lower NO emissions for the three cases tested (Tests 12, 15-18 and 97-98).

In lieu of a sufficient number of tests to generalize the results, previous LA APCD correlations[20] (Section 2.2) for oil combustion were used for the inventory calculations.

A significant result of the testing, in view of the refinery emphasis on safety and efficiency, was the large number of units having either high CO (combustible) or O_2 levels in the flue gas. A total of 18% of the units tested had significant CO levels (>200 ppm). A total of 49% had O_2 levels in the flue gas greater than 5% ($\approx$25% excess air). Clearly, systematic air register adjustment combined with good instrumentation could result in significant improvements in safety and operating economy.

C-3   REFINERY NOx EMISSION INVENTORY

In order to estimate the emissions of NOx from refinery heaters and boilers, the correlations developed were applied to all individual combustion devices inventoried. The assumption inherent in the calculations was that most inventory heaters and boilers were operated under conditions corresponding to the norm for which the correlations were developed. The main exceptions were several DeFlorez type heaters with burners oriented vertically downward which had very hot refractory crowns. The hot refractory seemed to be a consequence of the basic heater design rather than deviation from normal operating conditions. For those units the average emission factor of the tests conducted (.73 lb NOx/MMB) was applied to the six known units in operation. Also the average emission factor for the four CO boilers tested (.60 lb NOx/MMB) was used to estimate emissions from this type of device.

The basic procedure followed for each refinery was:

1. Determine rated unit heat input, capacity factors and oil/gas ratio from information provided by the refineries.

2. Determine the fuel use for the refinery from the LA APCD refinery fuel report.[31]

3. Correct the capacity factors so that the total fuel consumption of the units in each refinery is equal to (2). The distribution of fuel usage among the various combustion devices remained identical to information furnished by the refinery.

4. Calculate the emissions for a peak summer day, peak winter day, and average year using the correlations of Figure C-2 and the LA APCD correlation for oil combustion. (Figure 2-2)

5. Increase each unit by 5% to account for NO_2 (the test values are only for NO, as discussed in Section 8.0).

6. Increase each refinery total by 5% to reflect the CO fuel usage (which is not given in the LA APCD fuel report).

7. Calculate compressor emissions using the EPA factor (.027 lb NOx/HP). (Ref. 23)

8. Add (6) and (7).

The relations used and calculational procedures are summarized in Table C-VI.

The results are presented in Table C-VII which gives the emissions of NOx from refineries in the South Coast Air Basin for the fuel usage reported for the period of July 1972 to June 1973. Also shown for purposes of comparison are the LA APCD emission estimates for 1973[52] and 1974.[58]

These current estimates of NOx emissions from refineries in the South Coast Air Basin are significant in that they are twice as large as some previous estimates and 1-1/2 times the most recent. While the total is comparable to power plant NOx emissions in Los Angeles County, no known reduction efforts have been made.

Future trends will depend on the availability and type of crude supply and the possible implementation of reduction techniques. Most refineries are operating close to peak capacity. The only expansion plans currently in progress are for 125,000 Bbl/day additions at Atlantic Richfield and at Standard Oil by 1977-78.

In the Standard Oil Refinery addition, the total heater and boiler capacity is estimated to be 1489 MMB/H.[59] Assuming the Atlantic Richfield addition to be similar, and using the average refinery gas emission factor of .245 lb NOx/MMB, the totals for 1975 and 1980 would reach the values shown in Table C-VIII. The peak summer day NOx emissions for Atlantic Richfield and Standard Oil would reach 26.5 tons/day and 25.7 tons/day. In the winter (assuming the same emission factor for the additions) the rates would be 30.8 tons/day and 27.0 tons/day respectively. Complete curtailment of natural gas in the case of the refineries would result in the summer values increasing to the same general values as for the winter. As discussed in the next section of this appendix, a 20% reduction, which may be achieveable by application of staged combustion techniques, would reduce the 1980 totals of 104.4 tons NOx/day (summer) and 139.5 tons NOx/day (winter) by about 21 tons/day and 28 tons/day respectively.

TABLE C-VI

CALCULATIONAL PROCEDURE FOR REFINERY COMBUSTION DEVICES

Nomenclature

$\Sigma q_n = C_{F1}Q_1 + C_{F2}Q_2 \cdots \cdots + C_{Fn}Q_n$ = sum of average heat input to all refinery heat input to all refinery units as reported by refineries, MMB/h

$\overline{W}_{dec}$ = Average daily fuel consumption for December 1972, LA APCD Fuel Report, Bbl/d

$\overset{o}{W}_{dec}$ = Peak daily fuel consumption for December 1972, LA APCD Fuel Report, Bbl/d

$\overline{W}_{aug}$ = Average daily fuel consumption for August 1972, LA APCD Fuel Report, Bbl/d

$\overset{o}{W}_{aug}$ = Peak daily fuel consumption for August, 1972, LA APCD Fuel Report, Bbl/d

D_g = Average days on gas, 1972, days

D_O = Average days on oil, 1972, days

n = Number of burners for unit

Q_n = Rated capacity of unit, MMB/h

C_{Fn} = Capacity factor of unit, refinery value

$\overline{C}_{fwn}$ = Corrected winter average capacity factor

$\overset{o}{C}_{fwn}$ = Corrected winter peak day capacity factor

$\overline{C}_{fsn}$ = Corrected summer average capacity factor

$\overset{o}{C}_{fsn}$ = Corrected summer peak day capacity factor

$\overline{F}_{gs}$ = Emission factor on gas for average summer day, lb NOx/MMB

F_{gw} = Emission factor on gas for average winter day, lb NOx/MMB

$\overset{o}{F}_{gs}$ = Emission factor on gas for peak summer day, lb NOx/MMB

$\overset{o}{F}_{gw}$ = Emission factor on gas for peak winter day, lb NOx/MMB

$\hat{F}_{gs}$ = Emission factor on gas for unit at rated capacity, lb NOx/MMB

$\hat{F}_{gw}$ = Emission factor on gas for unit at rated capacity, lb NOx/MMB

E_{hs} = Peak hourly emissions in summer, lb/NOx/h

E_{hwg} = Peak hourly emissions in winter on gas, lb/NOx/h

E_{DS} = Daily emissions on peak summer day, tons NOx/day

E_{DW} = Daily emissions on peak winter day, Tons NOx/d

E_A = Annual emissions, Tons/NOx/year

$\overline{F}_O$ = Emission factor for oil on average winter day lb NOx/MMB

$\hat{F}_O$ = Emission factor for oil at rated capacity, lb NOx/MMB

$\overset{o}{F}_O$ = Emission factor for oil on peak winter day lb NOx/MMB

C-19

Calculation Relations

1. Input – NEDS Number and Case Number

2. Input – Σq_n, $\overline{W}_{dec}$, $\overset{o}{W}_{dec}$, $\overline{W}_{aug}$, $\overset{o}{W}_{aug}$, D_S, D_O, n, Q_n, C_{fn}

3. $\overline{C}_{fwn} = \left(\frac{1}{3.81}\right)\left(C_{fn}\right)\frac{\overline{W}_{dec}}{\Sigma q_n}$

4. $\overset{o}{C}_{fwn} = \left(\frac{1}{3.81}\right)\left(C_{fn}\right)\frac{\overset{o}{W}_{dec}}{\Sigma q_n}$

5. $\overline{C}_{fsn} = \left(\frac{1}{3.81}\right)C_{fn}\frac{\overline{W}_{Aug}}{\Sigma q_n}$

6. $\overset{o}{C}_{fsn} = \left(\frac{1}{3.81}\right)C_{fn}\frac{\overset{o}{W}_{Aug}}{\Sigma q_n}$

Case 1 – Natural Draft on Gas Only →

7. $\overline{F}_{gs} = \overset{o}{F}_{gs} = \hat{F}_{gs} = .135$

8. $\overline{F}_{gw} = \overset{o}{F}_{gw} = \hat{F}_{gw} = .135$

9. $E_{hs} = .135\, Q_n$

10. $E_{hwg} = .135\, Q_n$

11. $E_{Ds} = (.012)(.135)(\overset{o}{C}_{fsn})(Q_n) = .00162\, \overset{o}{C}_{fsn}\, Q_n$

12. $E_{Dw} = (.012)(.135)(\overset{o}{C}_{fwn})(Q_n) = .00162\, \overset{o}{C}_{fwn}\, Q_n$

13. $E_A = (2.196)(.135)(Q_n)\,(\overline{C}_{fsn} + \overline{C}_{fwn}) = .2965\, Q_n\,(\overline{C}_{fsn} + \overline{C}_{fwn})$

Case 2 – Natural Draft Burning Gas and Oil →

14. $\overline{F}_{gs} = \overset{o}{F}_{gs} = \hat{F}_{gs} = .135$

15. $\overline{F}_O = .175\,(Q_n\overline{C}_{fwn})^{.17}$

16. $\hat{F}_O = .175\, Q_n^{.17}$

17. $\overset{o}{F}_O = .175\,(Q_n\overset{o}{C}_{fwn})^{.17}$

18. $E_{hs} = .135\, Q_n$

19. $E_{hwo} = \hat{F}_o\, Q_n$

20. $E_{Ds} = .00162\, \overset{\circ}{C}_{fsn}\, Q_n$

21. $E_{Dw} = .012\, \overset{\circ}{F}_o\, \overset{\circ}{C}_{fwn}\, Q_n$

22. $E_a = (.012\, Q_n)(\overline{F}_{gs}\, \overline{C}_{fsn}\, D_g + \overline{F}_o\, \overline{C}_{fwn}\, D_o)$

Case 3 -- Forced Draft, Preheat, on Gas only

23. $\overline{F}_{gs} = .268\, (Q_n\, \overline{C}_{fsn}/n)^{.17}$

24. $\overset{\circ}{F}_{gs} = .268\, (Q_n\, \overset{\circ}{C}_{fsn}/n)^{.17}$

25. $\hat{F}_{gs} = .268\, (Q_n/n)^{.17}$

26. $\overline{F}_{gw} = .268\, (Q_n\, \overline{C}_{fwn}/n)^{.17}$

27. $\overset{\circ}{F}_{gw} = .268\, (Q_n\, \overset{\circ}{C}_{fwn}/n)^{.17}$

28. $\hat{F}_{gw} = .268\, (Q_n/n)^{.17}$

29. $E_{hs} = \hat{F}_{gs}\, Q_n$

30. $E_{hwg} = \hat{F}_{gw}\, Q_n$

31. $E_{Ds} = .012\, \overset{\circ}{F}_{gs}\, \overset{\circ}{C}_{fsn}\, Q_n$

32. $E_{Dwg} = .012\, \overset{\circ}{F}_{gw}\, \overset{\circ}{C}_{fwn}\, Q_n$

33. $E_A = (2.196\, Q_n)(\overline{F}_{gs}\, \overline{C}_{fsn} + \overline{F}_{gw}\, \overline{C}_{fwn})$

Case 4 - Forced Draft, Preheat, on Gas and Oil

34. $\overline{F}_{gs} = .268\, (Q_n\, \overline{C}_{fsn}/n)^{.17}$

35. $\overset{\circ}{F}_{gs} = .268\, (Q_n\, \overset{\circ}{C}_{fsn}/n)^{.17}$

36. $\hat{F}_{gs} = .268\, (Q_n/n)^{.17}$

37. $\overline{F}_O = .175 \ (Q_n \overline{C}_{fwn})^{.17}$

38. $\overset{\circ}{F}_O = .175 \ (Q_n \overset{\circ}{C}_{fwn})^{.17}$

39. $\hat{F}_O = .175 \ (Q_n)^{.17}$

40. $E_{ns} = \hat{F}_{gs} \ Q_n$

41. $E_{hwo} = \hat{F}_O \ Q_n$

42. $E_{DS} = .012 \ \overset{\circ}{F}_{gs} \ \overset{\circ}{C}_{fsn} \ Q_n$

43. $E_{DWo} = .012 \ \overset{\circ}{F}_O \ \overset{\circ}{C}_{fwn} \ Q_n$

44. $E_A = .012 \ Q_n \ (\overline{F}_{gs} \ \overline{C}_{fsn} \ D_g + \overline{F}_O \ \overline{C}_{fwn} \ D_o)$

Case 5 - Forced Draft, No Preheat, Gas only

45. $\overline{F}_{gs} = .158 \ (Q_n \ \overline{C}_{fsn}/n)^{.17}$

46. $\overset{\circ}{F}_{gs} = .158 \ (Q_n \ \overset{\circ}{C}_{fsn}/n)^{.17}$

47. $\hat{F}_{gs} = .158 \ (Q_n/n)^{.17}$

48. $\overline{F}_{gw} = .158 \ (Q_n \ \overline{C}_{fwn}/n)^{.17}$

49. $\overset{\circ}{F}_{gw} = .158 \ (Q_n \ \overset{\circ}{C}_{fwn}/n)^{.17}$

50. $\hat{F}_{gw} = .158 \ (Q_n \ \hat{C}_{fwn}/n)^{.17}$

51. $E_{ns} = \hat{F}_{gs} \ Q_n$

52. $E_{hwg} = \hat{F}_{gw} \ Q_n$

53. $E_{ds} = .012 \ \overset{\circ}{F}_{gs} \ \overset{\circ}{C}_{fsn} \ Q_n$

54. $E_{dwg} = .012 \ \overset{\circ}{F}_{gw} \ \overset{\circ}{C}_{fwn} \ Q_n$

55. $E_A = (2.196 \ Q_n) \ (\overline{F}_{gs} \ \overline{C}_{fsn} + \overline{F}_{gw} \ \overline{C}_{fwn})$

Case 6 - Forced Draft, No Preheat, Gas and Oil

56. $\overline{F}_{gs} = .158 \ (Q_n \ \overline{C}_{fsn}/n)^{.17}$

57. $\overset{o}{F}_{gs} = .158 \ (Q_n \ \overset{o}{C}_{fsn}/n)^{.17}$

58. $\hat{F}_{gs} = .158 \ (Q_n/n)^{.17}$

59. $\overline{F}_O = .175 \ (Q_n \overline{C}_{fwn})^{.17}$

60. $\overset{o}{F}_O = .175 \ (Q_n \ \overset{o}{C}_{fwn})^{.17}$

61. $\hat{F}_O = .175 \ (Q_n)^{.17}$

62. $E_{hs} = \hat{F}_{gs} \ Q_n$

63. $E_{hwo} = \hat{F}_O \ Q_n$

64. $E_{DS} = .012 \ \overset{o}{F}_{gs} \ \overset{o}{C}_{fsn} \ Q_n$

65. $E_{DWO} = .012 \ \overset{o}{F}_O \ \overset{o}{C}_{fwn} \ Q_n$

66. $E_A = .012 \ Q_n \ (\overline{F}_{gs} \ \overline{C}_{fsn} \ D_g + \overline{F}_O \overline{C}_{fwn} \ D_O)$

TABLE C-VII

SUMMARY OF NOx EMISSIONS FROM

LOS ANGELES COUNTY REFINERIES

Refinery	August '72 Daily Avg.	December '72 Daily Avg.	Annual* Jul.'72-Jun.'73	LA APCD* [52] Daily,1973	LA APCD* Annual 1974
ARCO	22.1	26.4	7711	8.6	4097
Gulf	2.4	3.2	873	1.5	663
Mobil	14.3	21.5	3759	7.0	3096
Powerine	1.9	2.6	720	.7	348
Shell	9.3	12.7	3419	5.8	2709
Standard	21.3	22.6	6882	10.1	4520
Texaco	10.4	19.9	3444	4.9	2219
Union	10.6	16.4	3508	5.0	2392
Misc.	9.3	10.3	2525	1.8	990
TOTAL	101.6	135.6	32,837	45.4	21,030

* Tons of NOx

TABLE C-VIII

FUTURE TRENDS OF NOx EMISSIONS
IN REFINERIES WITH NO REDUCTION IMPLEMENTED
AND NO FURTHER GAS CURTAILMENT

	PEAK SUMMER DAY (TONS)	PEAK WINTER DAY (TONS)	ANNUAL (TONS)
Current	101.6	135.6	32,837
1975	Same	Same	Same
1980	110.	144.	36,000

C-4   REFINERY EMISSION REDUCTION POTENTIAL

The heaters used in refineries are for the most part low emitters of NOx. However, it may be possible to reduce these emissions to even lower levels by the use of low excess air, staged combustion, and in some units flue gas recirculation. It is estimated that it may be practical to reduce the emissions to two-thirds of the heaters, while the emissions from the other one-third of the heaters might not be readily reduced by this technique which is discussed in Section 2.3.

Reduction schemes which resulted in cost effectiveness ratios (defined in Section 11.1) of less than one lb of NOx as NO_2 eliminated per dollar annualized cost were not considered in this report. The total nitric oxide emissions from LA basin refinery heaters, it is estimated, could be reduced by about 30% by off-stoichiometric firing -- one form of staged combustion. For the most part, off-stoichiometric firing would be accomplished by removing 10-30% of the burners from service, but staged combustion could also be accomplished by installing ports through which part of the air could enter the furnaces above the flames. The emissions from the boilers are higher than they are from heaters. The possible reasons are:

- boilers are for the most part larger than heaters,
- the boilers usually have air preheat while only part of the heaters have air preheat, and
- boilers have only a few large burners while many heaters have a great number of small burners.

The emissions from boilers are also subject to control by off-stoichiometric firing. By employing this technique on all boilers it is estimated that it would be possible to reduce the emissions from boilers by 35-40%.

Table C-IX shows the estimated first level emission reduction potential for the units tested. Shown in the table are the tested heating rate, the nitric oxides emitted per year, the amount by which the annual emissions would be reduced by the proposed techniques, and the amount of emissions eliminated per dollar annualized cost.

TABLE C-IX

EMISSION REDUCTION POTENTIAL

KVB Test No.	Tested Heat Rate	NOx	NOx Reduction	Method *	Cost Effectiveness Ratio +
	Btu/hr	lb/yr	lb/yr		lb/$

Heaters

KVB Test No.	Tested Heat Rate	NOx	NOx Reduction	Method *	Cost Effectiveness Ratio +
20	74×10^6	111,000			
23	62×10^6	172,000	25,000	O/S	5
24	62×10^6	456,800	228,400	O/S	39
25	39×10^6	456,800	228,400	O/S	37
38	82×10^6	347,000	130,000	O/S	45
48	180×10^6	399,200	100,000	O/S	24
48	180×10^6	399,200	100,000	FGR	24
49	105×10^6	380,200	120,000	O/S	40
49	105×10^6	380,200	120,000	FGR	40
54-55	167×10^6	454,000	100,000	O/S	32
57	256×10^6	353,600			
58-59	113×10^6	308,400	104,000	O/S	26
58-59	113×10^6	308,400	104,000	FGR	26
65	74×10^6	119,200	29,000	O/S	9.7
65	74×10^6	119,200	29,000	FGR	5.8
66-67	130×10^6	300,000	35,000	LEA	17
66-67	130×10^6	300,000	105,000	O/S	15
68	241×10^6	287,200	13,000	LEA	5.2
68	241×10^6	287,200	52,000	O/S	8.7
70	24×10^6	47,200	19,200	O/S	8.5
70	24×10^6	47,200	9,100	LEA	9.1
71	18×10^6	34,600			
96	394×10^6	405,000	80,000	O/S	20
97	141×10^6	132,000			
100	217×10^6	397,600	60,000	O/S	15
103	68×10^6	46,600			

5800-179

KVB Test No.	Tested Heat Rate	NOx	NOx Reduction	Method [*]	Cost Effectiveness Ratio [+]
	Btu/hr	lb/yr	lb/yr		lb/$

Boilers

KVB Test No.	Tested Heat Rate	NOx	NOx Reduction	Method	Cost Effectiveness Ratio
12	397×10^6	1,579,000	630,000	O/S	126
15	342×10^6	911,600	230,000	O/S	46
35	35×10^6	75,600	14,000	O/S	36
36	64×10^6	75,600	14,000	O/S	36
50	175×10^6	700,000	350,000	O/S	70
50	175×10^6	700,000	350,000	FGR	70
52	199×10^6	608,000	230,000	O/S	46
53	212×10^6	608,000	308,000	O/S	51
53	212×10^6	608,000	308,000	FGR	51
60	150×10^6	115,400			
101	224×10^6	1,110,400	500,000	O/S	130

CO Boilers

KVB Test No.	Tested Heat Rate	NOx	NOx Reduction	Method	Cost Effectiveness Ratio
13	$\simeq513 \times 10^6$	2,138,400			
37	60×10^6	347,000			
72	291×10^6	1,194,000			
102	$\simeq321 \times 10^6$	2,260,000			

[*] Symbols are O/S for Off-Stoichiometric firing, LEA for Low Excess Air, and FGR for Flue Gas Recirculation.

[+] These figures indicate the amount of NOx eliminated per annualized cost in pounds of NO_2 per dollar.

5800-179

The information on this table was generated by field inspection of all units tested by KVB personnel experienced in NOx reduction by staged combustion and other techniques.

Estimated costs include both those for setting up and implementing the combustion modifications and for instrumentation necessary to maintain the desired combustion conditions. These costs, which typically run in the $10,000 to $30,000 per unit range, more or less independent of unit size, have been annualized at the rate of 20% per year for the purpose of the cost effectiveness estimate. No loss of fuel efficiency has been assumed for these units since very few are adjusted for minimum excess air at present. Further discussion on reductions costs is presented in Section 11.

Most of the boiler emissions were judged to be reducible although none were estimated to be reducible by more than 50%. While many utility boilers burning natural gas have had their emissions reduced by more than that by off-stoichiometric firing, for the purpose of obtaining conservative estimates, 50% was chosen as an arbitrary upper limit for reduction. Reductions beyond those achieved by off-stoichiometric firing could be made, but they would be at lower cost effectiveness ratios. (See discussion of reduction cost effectiveness for utility boilers in Appendix D.) Another technique of NOx reduction suggested by the test program is managing the fuel distribution. Combustion with refinery gas with larger amounts of hydrogen (lower heating values) appeared to result in lower NOx emissions than those produced by higher heating value fuel. In some cases oil fuel gave lower values of NOx than higher heating value refinery gas. It may be possible to manage the gas distribution to high emitters in such a manner that lower total emissions can be achieved than with existing fuel distributions. For example, the DeFlorez heaters of tests 26 and 31 had NO concentrations that changed from 1011 ppm to 596 ppm and from 568 ppm to 230 ppm as the gas composition changed. If these units could be operated with the gas composition producing the lower emissions and other, lower emitters, operated with the higher heating value gas, the total emissions perhaps could be reduced.

The four CO boilers which were tested produced about one-third of the nitric oxide emissions measured from refineries. The low flame temperature which results from the combustion of the low heating value gas, CO and other combustibles diluted with N_2 and CO_2, should produce little nitric oxide. The NO concentrations in fact are fairly low for these boilers. However, the flue gas flow rates are increased by the diluents which enter with the CO gas,therefore, multiplication of the NO concentration and the increased flue gas flow rate by the appropriate constants result in emissions on a lb/million Btu basis which are quite high. It is not clear why the emissions from these units should be high as they are. However, through discussions with refinery personnel it was learned that the CO gas contains ammonia. Ammonia nitrogen, like other fuel nitrogen, converts in part to NO during combustion and this could be the major source of NOx from these units. It was noticed when testing a CO boiler where the precipitator was upstream of the boiler that much lower emission factors were obtained. Removal of part of the ammonia as the sulfate or sulfite by putting the electrostatic precipitator before the boiler may be the mechanism for this improvement and possible could form the basis for reduction on other units. Since these CO boilers are very different from utility boilers in which emissions have been reduced by staged combustion and flue gas recirculation, it is difficult to see which techniques could be most effectively applied to CO boilers and to predict what the results would be.

C-5   CONCLUSIONS

Emissions of the oxides of nitrogen from refineries in the South
Coast Air Basin appear to be significantly greater than previously estimated.
Measurement of emissions from 49 combustion devices and application of the
results to the total inventory of refinery heaters, boilers and compressors
showed the emissions to be more than twice the 1973 LA APCD estimate and
1-1/2 times the 1974 LA APCD estimate. The refinery total was found to be
comparable to the total NOx emissions from power plants in Los Angeles County
which have been regulated with respect to NOx emissions for some time. It
is conservatively estimated that a one-third reduction in refinery heater and
boiler NOx emissions might be achieved with combustion modifications alone,
resulting in a total decrease of about 26 tons/day at a cost effectiveness
that is favorable with respect to other alternatives. Additional reductions
may be achievable with equipment modifications such as installing overfire
ports or flue gas recirculation, and possible fuel management, but a more
detailed cost-benefit analysis for individual units needs to be conducted
before the cost effectiveness can be predicted reliably. Because of the
potentially large reductions in NOx that could result from O/S combustion,
it is recommended that this technique be applied to selected units to evaluate
its effectiveness in refineries. Additional significant reductions in the
NOx emissions from gas fired stationary internal combustion engines used in
the refineries may also be possible and should be employed.

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23. "Stationary Internal Combustion Engines in the United States," C.R. McGowin, Shell Development, EPA-R2-73-210, April 1973.

31. Los Angeles County Refinery Fuel Use and Emissions for August 1972 - June 1973, LAC APCD, August 1973.

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52. "Major Point Sources of Air Pollution in Los Angeles County April 1973," LAC APCD newsrelease April 19, 1973.

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APPENDIX D

ELECTRIC UTILITIES

D-1   INTRODUCTION

Utility boilers for steam generation have long been recognized as
a major stationary source of NOx emissions because of the very great quantities
of fuel burned. Regulations implemented by various governmental agencies have
required extensive testing and development of control techniques. As a result
of these efforts the nature of NOx emissions from these sources is fairly
well defined.

Utility boilers are the largest stationary devices and as a result
exhibit a high NOx emission per unit heat input compared with other devices.
NOx emissions are generally highest at peak load. The variation with load,
however, can be significantly different in different boiler designs. In
general there is a greater variation with load when operating on gas fuel
compared with oil. Variation with gas fuel tends to be linearly proportional
to load while on oil fuel there frequently is only a small decrease in NOx
at reduced load. Operation on oil fuel consistently results in higher NOx
emissions than for gas fuel operation for controlled units in which NOx
emissions have been minimized. The current trend toward limited gas
availability will result in significant increases in NOx emissions during
the summer months for which gas has previously been the predominant fuel.

Control techniques employed include limiting excess air, taking
some burners out of service so that the remaining burners operate fuel rich,
reduction of inlet air preheat, injection of overfire air through special
air ports in the furnace downstream of the combustion air, recirculation
of flue gas into the windbox air and water injection. Each of these is
discussed further in Section 2.2 of this report. The objective of all these
techniques is to reduce temperatures and limit oxygen concentrations in the
flame zone.

The implementation of many of the control techniques, as required to meet current regulations, has resulted in substantial reductions of NOx emissions from utility sources particularly in the South Coast Air Basin. The cost effectiveness of further control becomes important as emissions become more difficult to reduce. The increasingly high fuel cost and shortages of both oil and gas place limitations on any control techniques that result in a reduced operating efficiency.

The nature of the NOx inventorying problem for utility boilers is that emissions for operation on a particular fuel are well defined. Thus the major tasks in assembling an accurate inventory and projection involve the fuel type useages, generation growth projections, and cost effectiveness of known reduction techniques.

Among the stationary sources of NOx, utility boilers constitute one of the most clearly defineable device categories. There are five utility companies in the South Coast Air Basin having a total of 70 steam-powered generating units that are currently active. Some of these units have more than one boiler but exhaust to a single stack. In addition there are 11 gas turbine peaking units consisting of one to eight gas turbines, all of which, in a given unit, are operated simultaneously at equal load.

As a result of stringent regulations and resultant extensive compliance testing NOx characteristics of most of the larger utility boilers are well characterized. Accuracy of an emission inventory for these units is limited only by the ability to characterize the inherent day-to-day variability of operating conditions and relate known data to these conditions. However, of the 70 steam units in the Basin, 48 smaller units were unregulated before 1975 and 42 will remain unregulated after January 1, 1975. Nevertheless, tests have been conducted on many of the unregulated units in the process of establishing regulations so that, although less well known than for the regulated units, the emissions characteristics of approximately 60 percent of the unregulated units are reasonably well established by recent measurements.

Prior to the current program compilations of utility NOx emissions were assembled by the various basin air pollution control districts[1,3,5,6,47] and the California State Air Resources Board.[48]

For the purpose of establishing test priorities the preliminary inventory conducted during this program, as discussed in Section 7.0, identified three groups of utility company boilers according to the quality of available data and the status of emissions regulations. In general units over 1775 MMBtu/hr (about 180 Mw) were subject to regulation during the inventory period of July 1972 to June 1973. Specific regulations vary from county to county as shown in Table D-I.

Of the three identified groups, the first consists of 22 large boilers that are subject to regulations. Since extensive compliance testing has been conducted on the units the uncertainty in NOx emissions is sufficienty low so that additional testing would not be expected to reduce the uncertainty. The remaining uncertainty is primarily related to operational variability as discussed in Section 2.2.

The second group consisted of 30 medium sized boilers not subject to regulations but for which data generally on a par with that from the larger boilers was available. Eight of these units, all rated at 175 Mw (1725 MMBtu/hr), are essentially identical. However, there was a significant variation in the existing emissions data for the units. Accordingly one unit from this group was selected for test to provide information of use in reducing the uncertainty.

The third group identified consisted of 18 small units for which data was questionable or not avialable. These units range up to 70 Mw rated power (914 MMBtu/hr). Eight of these units range from 60 to 70 Mw and the remaining are less than 45 Mw. Two identical 70 Mw units and one 60 Mw unit were selected for test. The 70 Mw units actually consist of two boilers at 35 Mw each. The units selected for test are therefore representative of the majority of the larger units in the third group.

TABLE D-I

SUMMARY OF SOUTH COAST AIR BASIN NOx REGULATIONS

County / Rule	Los Angeles	Orange	Riverside West Central	Santa Barbara SCB	San Bernardino	Ventura
Rule New Units limit lb NOx/hr	67 140	67 140 >250 $\frac{MMB}{H}$ Gas: 125 ppm Oil: 225 ppm	72 140 West Central	39 140	67 140	60 140
Rule existing units	68	68	72.1	39.1	68	59
Applies to $\frac{MMB}{H}$	>1775	500-2150	>700			All
Date	12/31/71	12/31/72	12/31/71			10/6/69
Gas ppm	225	225	225			250
Oil ppm	325	325	325			250
Applies to $\frac{MMB}{H}$	>1775	>2150	>700	All	500-1775 (Steam only)	>2150
Date	12/31/74	12/31/72	12/31/74	1/1/75	1/1/75	1/1/75
Gas ppm	125	225	125	125	125	125
Oil ppm	225	325	225	225	225	225
Applies to $\frac{MMB}{H}$		>2150			>1775	
Date		1/31/75			1/1/75	
Gas ppm		125			125	
Oil ppm		225			225	

A large number of the smallest units are on cold stand-by or operate infrequently so that, although uncertainty may be high, the contribution to Basin emissions is small and testing would not provide effective improvement of the inventory.

D-2 MEASUREMENT OF NOx EMISSIONS FROM UTILITY BOILERS

As a result of extensive compliance testing of utility boilers the techniques for accurate NOx measurement are well established. Flue gas sampling is performed where possible ahead of the air preheater to eliminate preheater leakage influence. Exhaust ducts in utility boilers are large and multiple burner configurations can result in spacial variations in species concentrations across the duct. It is therefore necessary to sample at a number of points in the duct to arrive at a suitable average. Details of sample handling and instrumentation are discussed in Section 8 of this report.

Utility boiler operation is normally very steady so that a given load can be maintained throughout a test. Unless prempted by electrical system demands it is generally possible to have the load varied so that characteristics versus load can be established. Variation of excess air is found to be important in NOx emissions. Where possible emissions are measured over the range of normal operating flue gas excess oxygen content. The amount of excess air is generally under the control of the boiler operator so that various levels can be requested and thus preset for tests.

As discussed in Section D-1, four boilers were selected for test. Tests were conducted over a range of loads for operation with both gas and oil fuels. The boilers were operated, for most of the tests, in their normal operation mode. For one boiler data was obtained for off-stoichiometric operation to assess the NOx reduction potential for this particular boiler with that control technique. In addition, for this same boiler, simultaneous operation on both oil and gas was evaluated as this operating mode is occasionally employed and has been usually observed to result in higher emissions than operation on either fuel alone.

Figure D-1 presents data for Burbank Public Service Olive Station Unit 4 rated at 60 Mw. This unit has a single boiler of Riley Turbo-fire type with six burners. The unit was tested from half to full load with operation on gas, oil and simultaneously on both fuels. Variation of NO with load shows a moderate variation for oil fuel typical of most units. Gas fuel operation resulted in lower NO that did not vary with load contrary to the more typical linear variation. Operation in dual fuel mode resulted in NO emissions higher than for either fuel alone. This characteristic has been observed on other units. From fuel use data obtained it is not possible to determine the amount of dual fuel operation on any unit. Accordingly the higher NOx emissions for dual fuel operation has not been incorporated into the inventories. Off-stoichiometric operation with 2 burners out of service on oil fuel at one load point resulted in a 12 percent reduction for this already low-emission unit indicating that this unit could be reduced below a 225 ppm regulation limit at full load.

Figure D-2 presents the data obtained for Southern California Edison Redondo Beach Station Unit 1. This unit consists of two single-face-fired boilers with six burners each. Data was taken on Boiler 12. The unit is rated at 70 Mw for full load operation of both boilers. Operation on oil fuel resulted in relatively constant NO emission over the 50 to 100 percent load range and gas fuel operation produced a linear decrease in NO with load. These characteristics are typical of many boilers. The change in NO variation with load at low load for gas fuel is a consequence of increased excess air necessary to maintain steam temperatures and prevent smoke or carbon monoxide emission as load is decreased. This characteristic is also typical of many boilers. Although meeting current regulations for large units when operating on oil, such regulations, if applied to this unit for gaseous fuel operation, would necessitate some level of combustion control for reduced NO emission. The cost effectiveness of such controls on units of this size is discussed later in this appendix.

Figure D-3 presents test results for SCE Redondo Beach Unit 2. This unit is rated at 70 Mw with two boilers and is identical to Unit 1 just

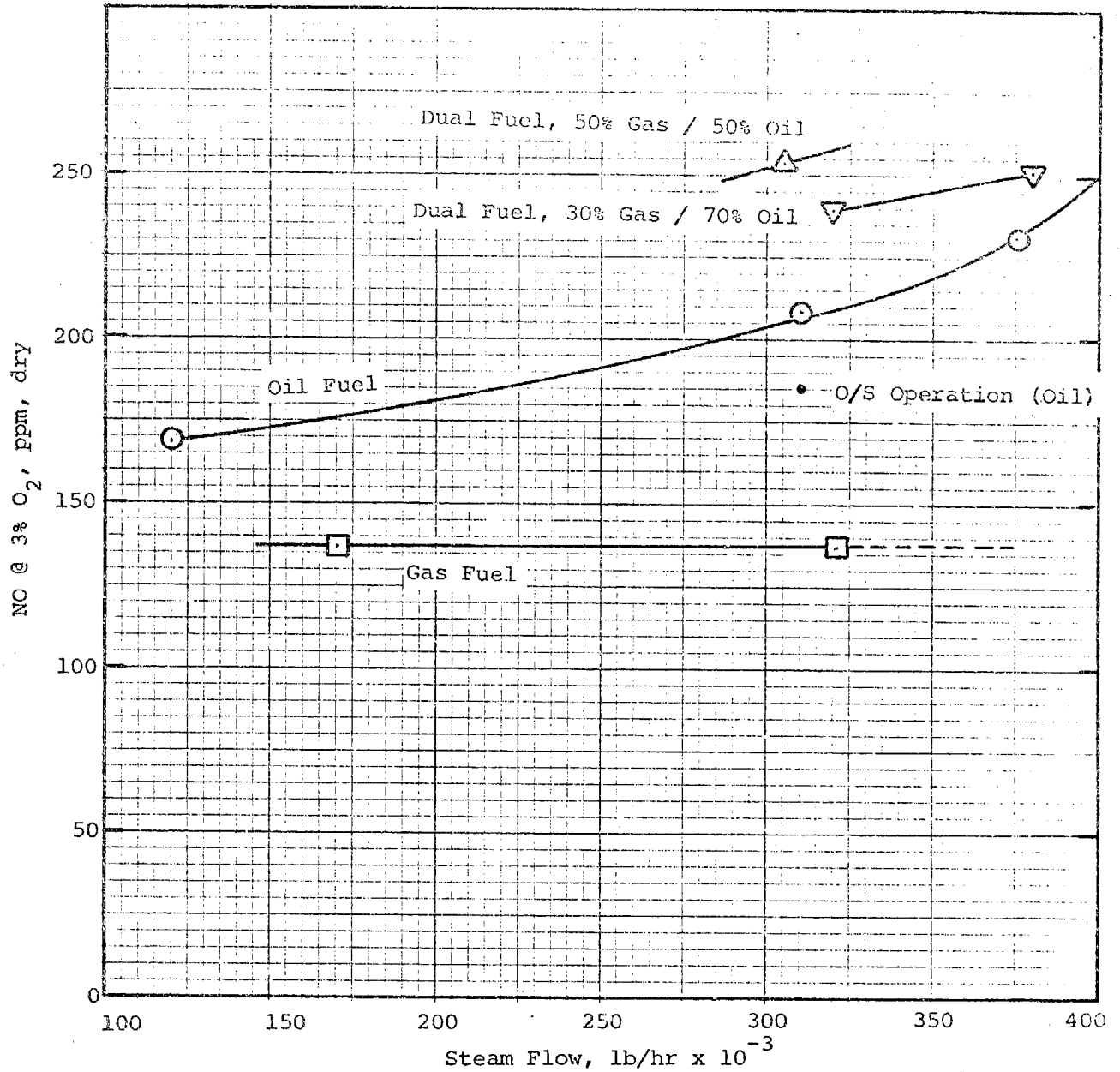Rated Load = 60 Mw @ 400000 lb Steam/hr

Figure D-1. NO Emissions From Burbank Olive Unit 2 For Normal Operation On Gas And Oil And On Dual Fuel, Tested 6/6/74 By KVB

Rated Load 70 Mw   2 Boilers at 400000 lb Steam/hr   Each
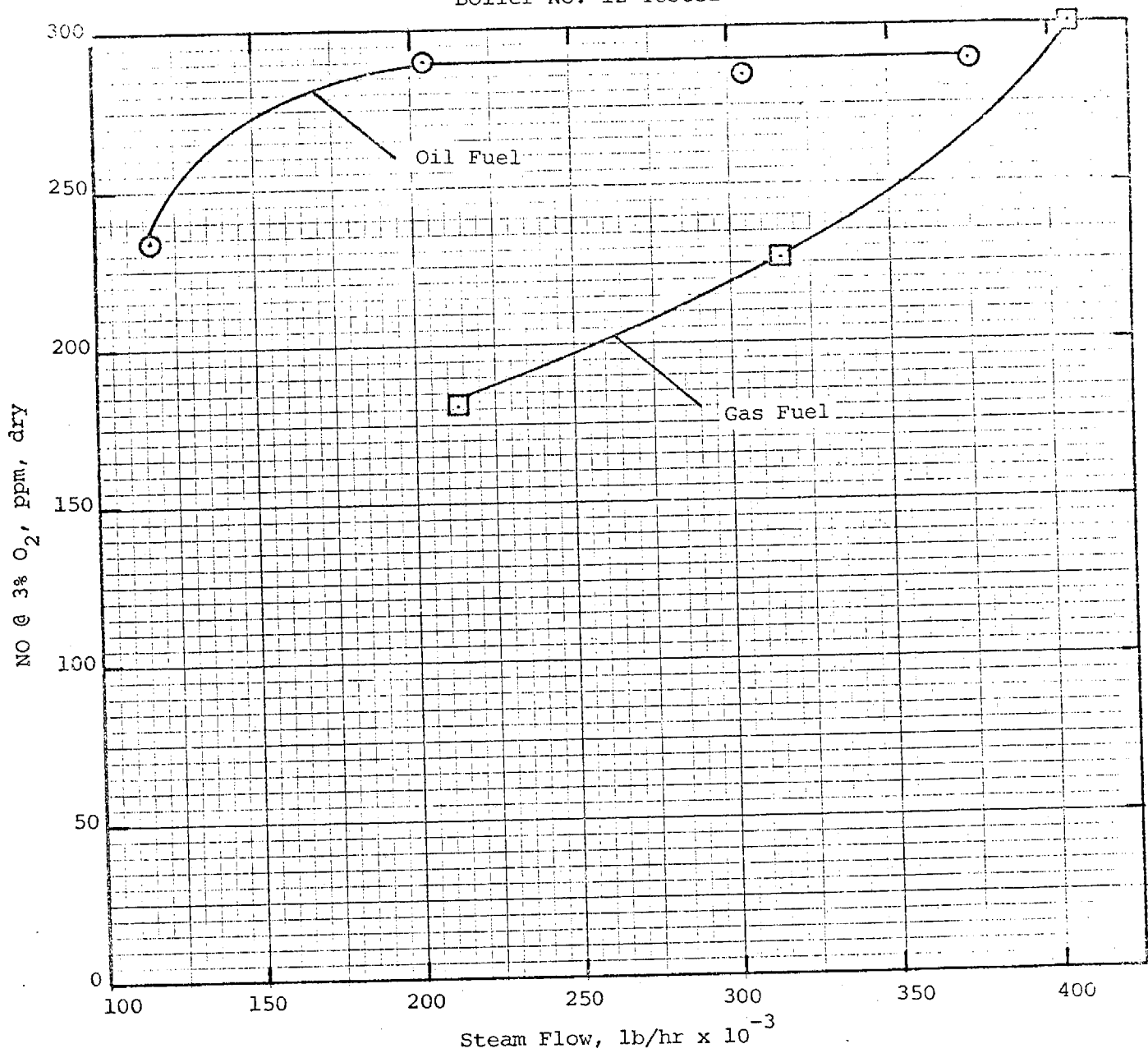Boiler No. 12 Tested

Figure D-2.   NO Emissions From SCE Redondo Beach Unit 1 For
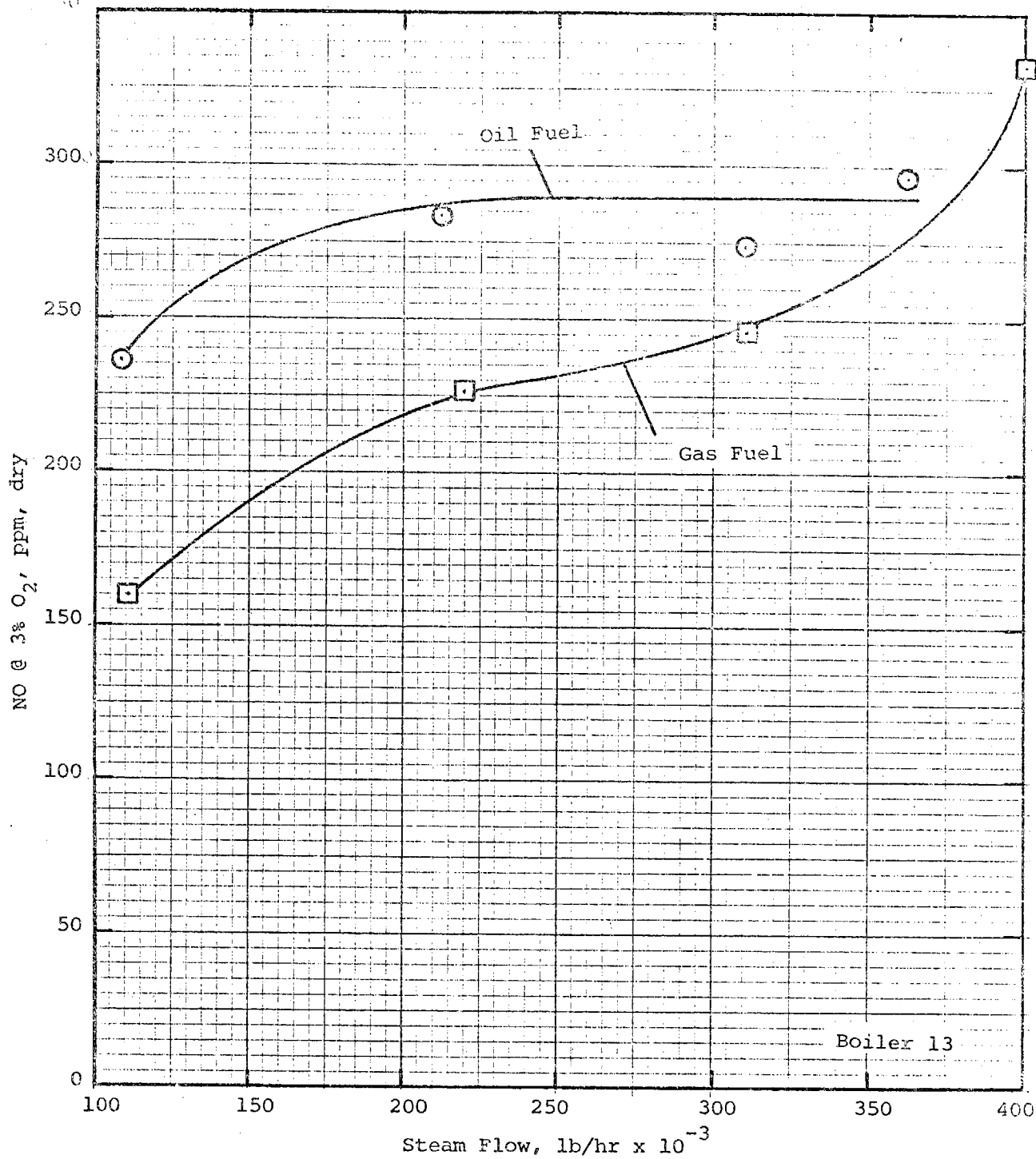Normal Operation On Gas And Oil Tested 6/11/74
By KVB

Figure D-3. NO Emissions From SCE Redondo Beach Unit 2 For
Normal Operation On Gas and Oil Fuel Tested
6/11/74 By KVB

5800-179

discussed. For oil fuel operation the NO emission is essentially identical to Unit 1 as shown in Figure D-2. Gas fuel operation is slightly different. NO decreases somewhat more rapidly from full load and continues to decrease with load instead of leveling off as was the case for Unit 1. Oxygen levels were higher in Unit 2 than in Unit 1 accounting for the relatively higher gas emissions in Unit 2 but this does not explain the drop in NO at low load for Unit 2. No definite explanation for this effect was apparent from the operational data obtained but this could be the effect of relative cleanliness of the two units.

Figure D-4 presents data for SCE Redondo Beach Unit 5 rated at 175 Mw with one single-face-fired boiler with 16 burners. For both fuels the NO decreases sharply with load to about 50 percent load and then increases as excess air is increased to maintain steam temperatures. This same data is replotted on a log-log graph in Figure D-5 to illustrate the exponential relationship between emissions and load (the parameter α, defined in equation 5-3, Section 5.1). Since most of the operation of a unit such as this occurs at load levels in excess of 50 percent of rated load, the departure from the exponential relationship at low load is of little consequence to the unit emissions inventory.

Table D-II compares, for the 60 to 70 Mw range units, the NO emission data available for the preliminary inventory[47] to the data selected for the final inventory. It is observed that for the final inventory data the units fall into two groups. The 70 Mw group consists of single-face-fired (Redondo 1-4) and opposed-face-fired (Broadway) burner arrangements. The second group consists of a Riley Turbo-fire (Olive) and two Combustion Engineering corner-fired (San Bernardino) burner arrangements. Although not entirely similar the units in each group contain sufficient similarities in flame structure to explain the emissions grouping. In general it is expected that corner and turbo-fired units have lower NO emissions than face fired types.
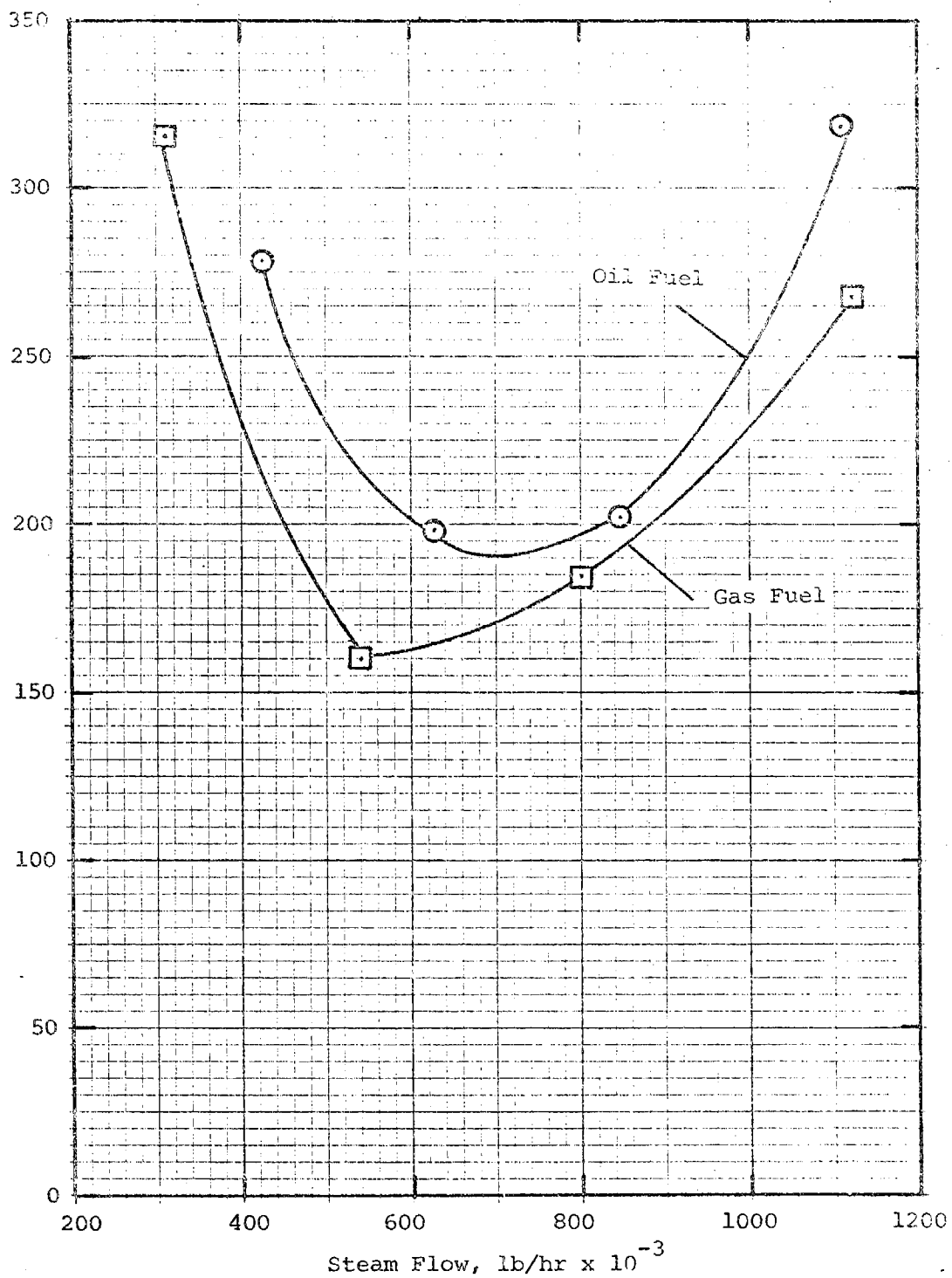
Rated Load = 175 Mw at 1140000 lb Steam/hr

Figure D-4. NO Emissions From SCE Redondo Beach Unit 5 For
Normal Operation On Gas And Oil Fuel Tested
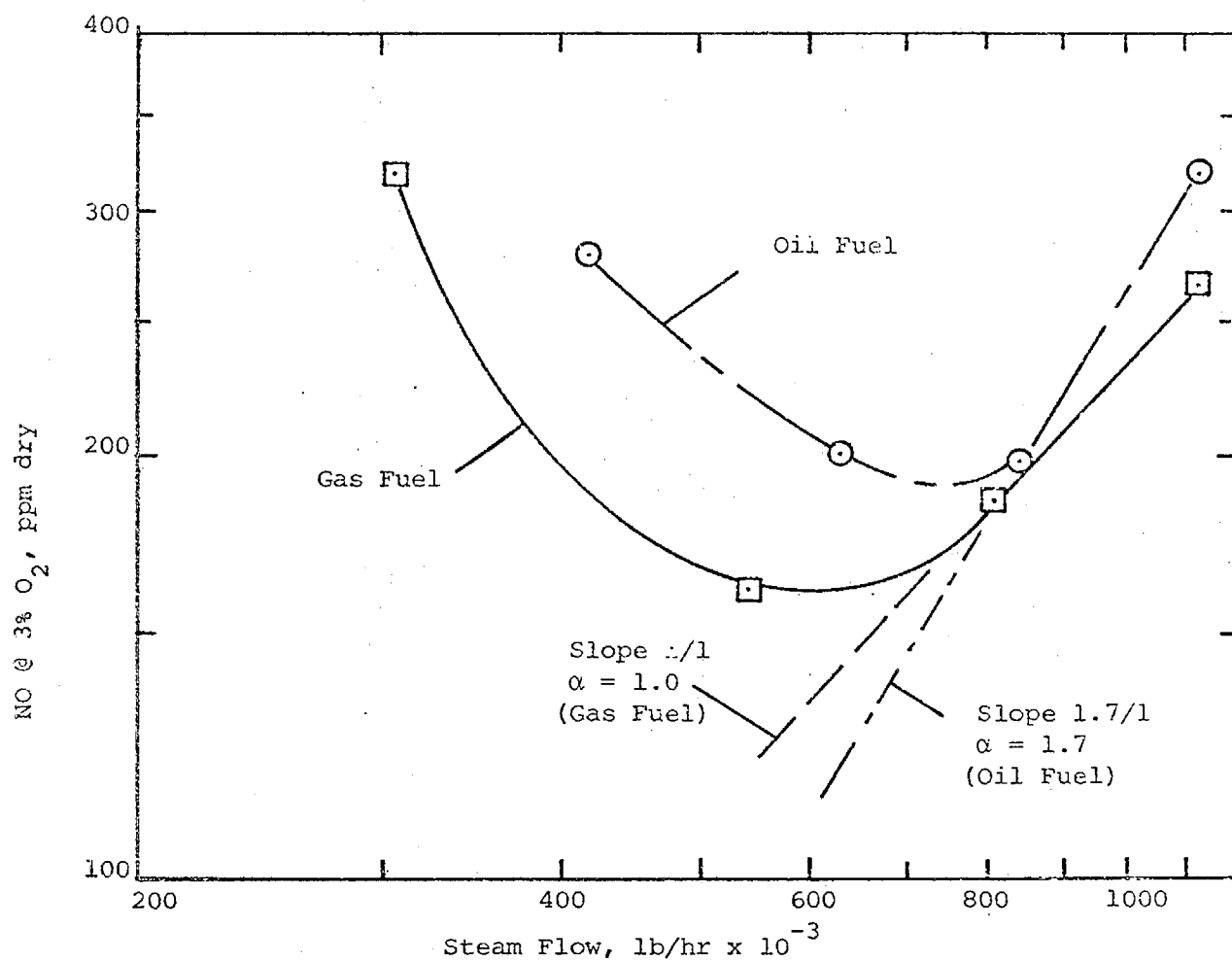6/13/74 By KVB

5800-179

Figure D-5.   NO Emissions From SCE Redondo Beach Unit 5
Showing Exponential Variation Of NO With Load
(Data From Figure D-4)

TABLE D-II

COMPARISON OF NOx EMISSION DATA FOR 60-70 Mw UTILITY BOILERS

| Unit | Mw | Peak Load NO, 3% O_2, ppm dry ** | | | | No. of Burners | Furnace Type |
| | | Preliminary Inventory Data [47] | | Data Selected For Final Inventory | | | |
		Gas	Oil	Gas	Oil		
*Redondo 1	70	400-500	350-650	300	290	6	single-face-fired***
*Redondo 2	70	400-500	350-650	330	300	6	"
Redondo 3	70	400-500	350-650	330	300	6	"
Redondo 4	70	400-500	350-650	330	300	6	"
Broadway B3	70	250-320	205-260	320	260	10	opposed-face-fired
Mean		402	424	310	290		
Standard deviation		96	187	14	17		
*Olive 2	60	195-237	160-176	140	250	6	Riley Turbo-fire
San Bern. 1	63	125-143	215-249	125	215	16	CE corner-fired
San Bern. 2	63	143-165	215-249	165	215	16	CE corner-fired
Mean		172	203	143	227		
Standard deviation		39	39	20	20		

*indicates units tested in current program

**sources of data and methods of selecting data for inventory are presented
in Tables D-XIV, D-XV and D-XVI

***Redondo 1-3 consist of 2 boilers each
Redondo 4 consists of 1 boiler

5800-179

Table D-III compares the 175 Mw units. For gas fuel operation test results obtained during this program for Redondo 5 brought that unit more in line with the other units, all grouped within 50 ppm except for Valley 4. For oil fuel operation the previous data indicated similarity between Redondo 5 and 6 and El Segundo 1 and 2, while Alamitos 1 and 2 were similar to Valley 3 and 4. Test of Redondo 5 indicated higher NO on oil than previous data so that all units except El Segundo 1 and 2 are similar. Data for El Segundo 2 were available from SCE[43] taken in 1971 and the lower emissions are attributed to off-stoichiometric operation during the test that does not represent the normal operating mode.

According to SCE the three SCE 175 Mw units are of identical design. Accordingly the emissions for El Segundo 1 and 2 were adjusted in the final inventory to that of the Redondo 5 test. The Valley 3 and 4 units are also single-face-fired boilers but have 20 burners and are of a different design and manufacturer (Riley).

As seen in both the foregoing tables, application of the test data resulted in a significant reduction in the variation between emissions of units within a given class, as reflected by the standard deviations listed in the tables.

TABLE D-III

COMPARISON OF NOx EMISSION DATA FOR 175 Mw UTILITY BOILERS

Unit	Peak Load NO, 3% O$_2$, ppm dry**				No. of Burners	Boiler Type
	Preliminary Inventory Data		Data Selected For Final Inventory			
	Gas	Oil	Gas	Oil		
Alamitos 1	229-245	207-350	245	350	16	single-face-fired
Alamitos 2	229-245	207-400	245	400	16	"
El Segundo 1	297-300	207-210	270	320	16	"
El Segundo 2	220-300	207-210	270	320	16	"
*Redondo 5	297-300	207-210	270	320	16	"
Redondo 6	297-300	207-210	270	320	16	"
Valley 3	177-225	350-485	225	350	20	"
Valley 4	175-190	330-485	175	330	20	"
Mean	247	299	246	339		
Standard Deviation	50	111	33	28		

*indicates unit tested in current program

**sources of data and method of selecting data for final inventory are presented in Tables D-XIV, D-XV, and D-XVI

5800-179

The 72-73 NOx inventory for utility boilers and gas turbines is summarized in Table D-IV showing August and December daily averages and annual average NOx emissions expressed as a daily average. Emissions for July 1972 to June 1973 are based on the accumulated data discussed later in this section and projections for 1975 and 1980 were made from estimates obtained from the utility companies for gas fuel availability and projected system generation growth. The most significant change occurs in the summer daily peak between 1973 and 1975. This is a consequence of a decrease in gas use from 43 percent of total fuel use in 1973 to about 5 to 10 percent in 1975 and results in the summer daily peak increasing to levels similar to the winter daily peak. A further increase occurs in 1980 because of increased power generation and essentially full operation on oil fuel.

The December daily average decreases in 1975 as the result of implementation of NO regulations at the end of 1974. In addition there is a projected reduction in power generation for the Los Angeles Department of Water and Power as the result of demand reduction and availability of power from outside the Basin.[42] For 1980 system generation growth results in the winter peak increasing above the 1973 level.

The Basin annual average NOx emission increases at annual rates of 5.3 and 4.8 percent for 1975 and 1980, respectively, relative to 1973. The generation rate increases at annual average rates of 0.6 and 2.6 percent for 1975 and 1980 respectively. Individual utility growth rates are discussed below. For 1975 although the growth rate is low the shortage of gas fuel results in an increase in NOx emissions. For 1980 both gas shortage and system load increases contribute to increased NOx. NOx emissions will increase at a higher rate than load because the NOx emitted per unit heat input generally increases as load factors increase. In 1973 the Basin utility system operated at an overall generating capacity of 49 percent while in 1980 this is expected to increase to 59 percent to meet projected load growth.

TABLE D-IV

UTILITY COMPANY POWER PLANT NOx EMISSIONS INVENTORY

	August Daily Average NOx, Tons/Day			December Daily Average NOx, Tons/Day			Annual Average NOx, Tons/Day		
	7/72-6/73	1975	1980	7/72-6/73	1975	1980	7/72-6/73	1975	1980
South. Cal. Edison	77.6	150.0	189.0	138.2	152.6	188.5	110.9	139.6	179.8
LA Dept. of W&P	32.8	43.3	47.4	66.9	45.9	50.3	49.9	42.6	47.9
Pasadena Dept of W&P	1.9	4.0	6.3	4.2	4.7	6.6	3.6	4.4	6.4
Burbank Pub. Serv.	1.4	2.6	3.3	2.2	2.7	3.5	1.9	2.6	3.4
Glendale Pub. Serv.	.7	3.1	2.7	3.5	3.5	3.1	2.3	2.9	2.8
	114.4	202.9	248.7	215.0	209.4	251.9	168.6	192.0	240.2
Percent Increase from 1973		18.	118.		-2.5	17.3		14.0	42.6
Annual average NOx Growth From 1973 level, Percent Per Year		26.	11.		-1.0	2.1		5.3	4.8
Annual Average Growth In Power Generation, Percent Per Year								0.6	2.6

Utility company preference for increasing the system output is to increase load on the larger more efficient units. In addition some utility companies employ a load scheduling pattern that minimizes NOx generation. However, as power demands increase a limit is reached where the larger units are at full practical capacity. Beyond this point, if power is not available from outside the Basin, the smaller units must be operated at increased load. Projections for the 1980 period indicate that this may well be the case particularly for the SCE utility system. Projections for SCE, discussed later in this section, were made on the assumption that only one new plant, a combined cycle system at Long Beach, will be added to the system by 1980 and no other new source of power in the Basin will be available in that time period.

Tables D-V through D-XII present the detailed inventory results for each of the 81 Basin units. These tables contain information, where available, regarding the boiler configuration and operating mode for which the indicated NOx emissions are applicable. Also tabulated are the exponents for load variation of NO concentration and the peak load NOx for gas and oil operation. The load exponents and peak load concentrations were used together with gas and oil use from APCD reports[30] and capacity factor data from the utility companies[42-46] to compute the days per year of operation on gas or oil, the peak load NOx emission rates, the August and December daily average NOx emission and an annual average NOx emission. The annual average NOx emission is tabulated as tons per days obtained by dividing the total tons emitted in one year by 365 days.

Boiler operating mode data has been included in the tabulations to clarify the validity of NOx emissions and to provide a means for assessing reduction potentials. An entry of ABIS means that all burners were in service during tests so that an overall excess of air occurs throughout the combustion zone. The operating mode entry, "BOOS", indicates "Burners out of service," the use of off-stoichiometric operation. An entry of 4/16, for example, indicates that of a total of 16 burners, 4 have no fuel flow. All

fuel flows to the remaining 12 burners that then operate fuel-rich for low NOx formation. Excess air from the 4 out-of-service burners mixes in after initial cooling to provide the overall excess air requirement.

The entry titled "NOx PORTS" refers to the use of air ports in the furnace to bypass air around the burners so that they operate with less air and serve a similar purpose as burners out of service.

The entry labeled "BURNER TIPS" refers to the use of enlarged fuel tips to limit fuel pressure to the fired burners when other burners are out of service.

The entry "GAS RECIRC" relates to the use of recirculated flue gas directed into the burner windbox. This results in a deficiency of oxygen and a reduction in NO. For the purpose of this tabulation gas recirculation not introduced in the windbox for NOx control is considered "normal."

The entry "FURNACE CLEAN OR DIRTY" refers to the fact that clean furnace walls absorb more heat than dirty walls. NOx emission from a clean furnace is normally lower than for a dirty one. The furnace is clean after extended periods of gas operation or after the walls has been washed. Oil operation results in increasingly dirty walls.

The "OPERATING MODE" entry refers to either normal (N) or modified (M) operation. Normal operation in the context of the table means operation as the unit was originally designed. Modified operation implies some control techniques, primarily a modified burner service pattern, have been implemented for reduced NOx operation. These definitions may differ slightly from those of specific utility companies where modified operation has been implemented at all times so that this operating mode then becomes the "normal" mode for that unit.

The inventory data applicable to the July 1972-June 1973 time period is contained in Tables D-V, D-VIII, D-XI, D-XII and D-XIII. Boiler configurations, load exponents, peak load NOx concentration and unit capacity factors were obtained from information supplied by the utilities.[42-46] Fuel useage was obtained from APCD reports[30] and checked where possible against

utility fuel use reports. Capacity factors were determined from fuel useage for an entire station and compared with weighted average capacity factors determined from unit capacity factors based on power generation. These checks showed good consistency except for the smallest units where heat rates are most uncertain.

For the '72/'73 inventory it was noted that two large units, Ormond Beach 2 (SCE) and Scattergood 2 (LADWP) were in operation for only part of the period. In addition, for some units the August and December daily averages are listed as zero. This reflects that the unit was not in operation during August or December. This may not reflect a typical day for those particular units but in terms of the total Basin August and December averages the probability that some units will always be out of service suggests that the zero values are more applicable than some adjusted estimate assuming all units operate.

Peak load NOx concentration for the final inventory for '72/'73 were selected from among data available from several sources. Tables D-XIV, D-XV and D-XVI present these data and indicate sources and the selected values. In general the data provided by the respective utility companies were found to be more current and more directly related to specific boiler operating modes. Where utility company data were not available data for similar units were taken or ARB[48] and APCD[47] data were used. For units where KVB obtained data during the current NOx study those data were applied as previous discussed.

Detailed information for projections are contained, for 1975, in Tables D-VI, D-IX, D-XI, D-XII and D-XIII, and for 1980, in Tables D-VII, D-X, D-XI, D-XII and D-XIII. For units that are expected to comply with revised or new regulations after 1973 and for which existing data are in excess of these regulations the NOx emissions were assumed to be at the regulation limit. Specific boiler configurations are not listed in some cases since final operating modes are not yet completely available from the utilities. For units with no regulation change or currently below the future regulations; emissions were taken to remain at 1973 levels.

Projections to 1975 and 1980 for Southern California Edison (SCE), Tables D-VI and D-VII, were based on projected gas availability[43] of 8 percent in 1975 and one percent in 1980. Projected growth in generated power is estimated by SCE[43] to be 4.5 percent annual average from 1973 to 1975 and 4.6 percent annual average from 1973 to 1980. Growth rates for individual units were not available and it was found that for 1975 increasing Ormond Beach Unit 2 from 4 to 12 months operation provided the correct generation growth with all other SCE units remaining at the 1973 generation rate. The 1975 projection for SCE was therefore made on this basis. The 1980 projection for SCE was made by including a new Long Beach combined cycle gas turbine system consisting of 7 units for a total of 575 Mw. In addition the Ormond Beach Units 1 and 2 were assumed to have a generation growth rate of 4 percent. The remaining units were projected at a 2 percent growth rate necessary to meet the overall system annual growth rate of 4.6 percent. These growth rates were applied with further restrictions that no unit exceed in a given month load factor of .85 (average load/rated load) or a on-line factor of .97 (time on line/total possible on line). The load factor limit is based on a review of maximum load factors observed in the '72/'73 data. The on-line factor is based on a 2 week per year normal unit down time obtained from SCE.[43] These projections are believed to represent an upper limit on NOx emissions for the SCE system, as the current practice of optimum load scheduling for minimum NOx will undoubtedly be continued.

Projections for 1975 and 1980 for the City of Los Angeles Department of Water and Power (LADWP), Tables D-IX and D-X, were based on monthly capacity factors and gas availability obtained from that utility.[42] Because of recent demand reductions and the availability of power from outside the South Coast Basin, the generation rate decreases from 1973 to 1975 at an annual average rate of 10 percent and then remains relatively constant to 1980. Gas availability for LADWP in 1975 is projected[42] to be about 5 to 7 percent of total fuel use and drops to zero in 1976 through 1980. The Harbor station is currently on cold standby so that 1975 and 1980 emissions there will be negligible. Scattergood Unit 2 operated for only 2 months in 1973. For 1975 and 1980 projections operation of this unit was estimated to be

similar to Scattergood 1 with full year operation. Scattergood Unit 3, although currently becoming operational is on permit to burn gas only. In view of the lack of gas this unit was assumed to remain on cold standby for 1975 and 1980 with no emissions. If gas were available it is estimated that this unit would emit about 1.25 tons of NOx per day on an annual average.

Projected growth rates for the remaining three utilities for both 1975 and 1980 were taken at 4 percent per year based on estimates from each utility.[44-46] Gas availability was estimated to be 10 percent in 1975 and one percent in 1980. New units being added were included in the projections. These units are all gas turbine combined cycle systems, and in some cases replace boilers present in the 1973 summary.

UTILITY NOx EMISSIONS SUMMARY FOR 7/72-6/73

Utility: Southern California Edison

Station	Unit	Rated Load MW	Rated Heat Input MBH/H	Full Load BOOS Gas	Oil	NOx Ports Open(O)/Closed(C) Gas	Oil	Burner Fuel Tips Gas	Oil	Gas Recirc Gas	Oil	Furnace Clean(C)/Dirty(D) Gas	Oil	Op Mode Gas	Oil	NOx Load Exp αg Gas	αo Oil	Peak Load NO PPM @3%O2,Dry Gas	Oil	Days/Yr On Fuel Gas	Oil	Peak Load NOx Rate Lb NO2/Hr Gas	Oil	Aug. Daily Avg NOx 7/5	Dec. Daily Avg NOx 7/D	Annual Avg NOx 7/5	Notes
ALAMITOS	1	175	1725		ABIS		O		N		N		C	N	N	1.5	1.0	245	350	112	196	511	805	.96	1.34	2.29	
	2	175	1725		ABIS		O		N		N		C	N	N	1.5	1.5	245	400	77	204	513	920	.61	4.03	2.49	
	3	320	2840	ABIS	ABIS	X	X	N	N	MAX	MAX	C	C	N	N	.25	.5	200	230	79	117	698	871	5.39	7.64	3.55	(0)
	4	320	2840		ABIS		X		N		N			N	N	.25	.5	200	230	124	217	688	871	5.19	5.89	5.62	(1)
	5	480	4510		ABIS		C		N		N		D	N	N	1.3	.5	170	320	87	223	929	1924	4.04	14.04	9.46	(2)
	6	480	4510		ABIS		C		N		N		D	N	N	1.3	.5	170	320	129	136	922	1894	5.11	0.	6.12	(1)
	7-GT	121	1633	X	X	X	X	N	N	X	X	X	X	N	N	1.	1.	212	404	4	2	420	880	.19	0.	.89	
EL SEGUNDO	1	175	1725	ABIS	ABIS	C	C	L	L	N	N	D	D	N	N	1.0	1.7	270	320	59	270	565	736	2.58	3.30	2.75	
	2	175	1725	ABIS	ABIS	X	X	N	X	N	N	D	D	N	N	1.0	1.7	270	320	55	222	565	735	2.77	3.54	2.60	
	3	330	3101							X	X			N	N	1.5	.5	100	245	9	83	376	1012	0	0	1.49	(1)
	4	330	3101											N	N	1.5	.5	110	210	61	285	414	868	1.77	6.39	5.25	(2)
ETIWANDA	1	132	1326	ABIS	ABIS	X	X	N	N	X	X			N	N	1.2	.0	200	190	92	224	321	336	1.03	2.53	1.86	
	2	132	1326	ABIS	ABIS	X	X	N	N	X	X			N	N	1.0	-.5	200	195	86	204	378	345	.70	3.02	2.31	
	3	320	3040	ABIS	ABIS	X	O	N	N	N	X	C	C	N	N	.5	.5	120	210	126	174	442	851	3.62	6.31	4.15	
	4	320	3040	ABIS	ABIS	X	O	N	N	N	X	C	C	N	N	1.5	.3	140	210	122	215	516	851	3.54	6.72	4.94	
	5-GT	121	1633	X	X	X	X	N	N	X	X	X	X	N	N	.0	.0	546	495	126	226	1030	1030	.13	.13	.13	
HIGHGROVE	1	33	395							N	N			N	N	.0	.0	257	265	6	4	123	140	.07	.03	.03	
	2	33	395							N	N			N	N	.0	.0	257	265	6	2	123	140	.06	.03	.22	
	3	45	487							X	X			N	N	.0	.0	257	265	9	6	152	172	.10	.06	.05	
	4	45	487							X	X			N	N	.0	.0	257	265	16	18	152	172	.09	.03	.26	
HUNT BEACH	1	215	2043	6/24	6/24	X	X	N	L	N	N	D	D	M	N	.5	.25	165	245	142	200	458	667	2.59	4.45	3.65	(1)
	2	215	2043	6/24	6/24	X	X	N	L	N	X	D	D	N	M	.5	.5	150	300	133	202	371	917	1.67	5.82	3.57	(1)
	3	215	2043	6/24	6/24	O	N	N	N	N	X	C	D	N	M	1.0	.25	180	245	115	164	373	667	3.28	5.75	3.78	(also on gas)
	4	225	2138	6/24	ABIS	O	O	N	N	N	X	C	D	N	M	1.5	.1	200	300	142	199	519	655	2.82	6.12	5.19	(1)
	5-GT	121	1633	X	X	X	X	N	N	X	X	X	X	N	N	1.0	1.0	425	460	4	6	840	1001	.25	.09		
ORMOND B.	1	750	7125	8/32	3/32			N	L	15%	15%	C	C	M	M	3.	.5	250	245	121	190	2159	1955	8.31	18.16	12.69	(... oil)
	2	750	7125		8/32				L		15%		C	M	M	3.	.25	250	230	20	38	2159	2885	0	0	1.74	(... gas/oil)
MANDALAY	1	215	2020	6/24	6/24	X	X	L	L	N	N			M	M	.75	.4	200	220	132	142	490	593	1.19	3.69	2.64	(1)
	2	215	2020	6/24	6/24	X	X	L	L	N	N			M	M	1.	.3	170	220	121	107	416	593	2.90	1.92	1.72	(2)
	3-GT	121	1633	X	X	X	X	N	N	X	X	X	X	M	M	.0	.0	394	450	200	153	800	980	.19	.12	.18	

D-23

Note: N = Normal plant operating procedure
M = Modified burner pattern
BOOS = Burners out of service
ABIS = All burners in service
L = Oversized burner tips
X = Not applicable
α = NO load exponent: $PPM, NO, Reduced\ Load = (PPM, NO, Rated\ Load)^\alpha$
-GT = Gas turbine units, all others are steam units

* Units tested in KVB/ARB program
(1) NOx limited to 225 ppm on gas, 325 ppm on oil
(2) NOx limited to 225 ppm on gas or oil
(3) See Table D-XIV for data sources

TABLE D-V (Continued)

UTILITY NOx EMISSIONS SUMMARY FOR 7/72-6/73

Utility: Southern California Edison

Station	Unit	Rated Load MW	Rated Heat Input MMB/H	Full Load BOOS Gas	Full Load BOOS Oil	NOx Ports Open(O) Closed(C) Gas	NOx Ports Oil	Burner Fuel Tips Gas	Burner Fuel Tips Oil	Gas Recirc. Gas	Gas Recirc. Oil	Furnace Clean(C) Dirty(D) Gas	Furnace Oil	Operating Mode Gas	Operating Mode Oil	NOx Load Exponent α_g Gas	α_o Oil	Peak Load NO, PPM 3% O₂, Dry Gas	Oil	Days Per Year On Fuel Type Gas	Oil	Peak Load NOx Rate lb NO₂/Hr Gas	Oil	Avg. Daily Avg. NOx T/D	Dec. Daily Avg. NOx T/D	Annual Avg. NOx T/D	
REDONDO B.	1	70	914											N	N	1.	.0	300	290	78	61	332	353	.24	.82	.35	*
	2	70	914											N	N	1.	.25	330	300	172	64	365	365	.06	.57	.25	*
	3	70	914											N	N	1.	.0	330	300	68	45	365	365	.27	.85	.33	
	4	70	914					N	N		N		D	N	N	1.	.0	330	300	121	80	365	365	.15	.84	.39	*
	5	175	1725	ABIS	ABIS	X	X	N	N	N	N	D		N	N	1.	1.7	270	320	197	62	564	736	1.66	2.06	1.61	
	6	175	1725		ABIS	C	C	N	N	N	N	C	C	N	N	1.	1.7	270	320	231	111	564	736	2.30	2.54	2.33	(1)
	7	480	4341	8/32	ABIS	C	C	N	N	N	N	C	C	M	M	1.3	.12	170	225	174	83	894	1302	5.22	5.10	5.63	(1)
	8	480	4341	8/32	ABIS	X	X	N	N	N	N	C	C	M	M	1.0	.5	145	240	219	95	763	1369	5.66	13.18	7.43	(11,40 MW Gas)
SAN BERN.	1	63	599	ABIS	ABIS	X	X	N	N	X	X	C	D	N	N	.25	.25	125	215	272	72	91	171	.77	1.50	.90	
	2	63	599	ABIS	ABIS	X	X	N	N	X	X		D	N	N	.5	.0	165	215	223	60	120	171	.92	1.09	.85	
																								77.6	138.2	110.9	

Note: N = Normal plant operating procedure
M = Modified burner pattern
BOOS = Burners out of service
ABIS = All burners in service
L = Oversized burner tips
X = Not applicable
α = NO load exponent: $PPM_{NO,Reduced\ Load} = PPM_{NO,Rated\ Load}{}^{\alpha}$

-GT = Gas turbine units, all others are steam units

* Units tested in KVB/ARB program
(1) NOx limited to 225 ppm on gas, 325 ppm on oil
(2) NOx limited to 250 ppm on gas or oil
(3) See Table D-XIV for data source

D-24

UTILITY NOx EMISSIONS SUMMARY – PROJECTION FOR 1975

Utility: Southern California Edison

Station	Unit	Rated Load Mw	Rated Heat Input KKB/H	Full Load BOOS Gas	Full Load BOOS Oil	NOx Ports Open(O) Closed(C) Gas	NOx Ports Open(O) Closed(C) Oil	Burner Fuel Tips Gas	Burner Fuel Tips Oil	Gas Recirc. Gas	Gas Recirc. Oil	Furnace Clean(C) Dirty(D) Gas	Furnace Clean(C) Dirty(D) Oil	Operating Mode Gas	Operating Mode Oil	NOx Load Exponent α_g Gas	NOx Load Exponent α_o Oil	Peak Load NO, PPM 3% O_2, Dry Gas	Peak Load NO, PPM 3% O_2, Dry Oil	Days Per Year On Fuel Type Gas	Days Per Year On Fuel Type Oil	Peak Load NOx Rate Lb NO_2/Hr Gas	Peak Load NOx Rate Lb NO_2/Hr Oil	Aug. Daily Avg. NOx T/D	Dec. Daily Avg. NOx T/D	Annual Avg. NOx T/D	
ALAMITOS	1	175	1725											N	N	1.5	2.0	245	350	25	278	513	805	2.09	1.34	2.66	
	2	175	1725		ABIS		X	N	N	N	N			N	N	1.5	1.5	245	400	23	254	513	920	1.10	4.04	2.68	
	3	320	2840	ABIS	ABIS	X	X	N	N	N	N			N	N	.25	.50	125	225	16	180	430	852	6.24	6.89	3.54	(3)
	4	320	2840	ABIS	ABIS	X	X	N	N	N	N			N	N	.25	.50	125	225	27	308	430	852	5.95	5.75	5.60	(3)
	5	480	4510	8/32	8/32	C	C	N	L	N	N			N	N	1.3	.3	125	225	25	280	687	1252	7.76	9.65	7.71	(3)
	6	480	4510	8/32	8/32	C	C	N	L	N	N			N	N	1.3	.5	125	225	21	222	683	1353	9.76	0	6.00	(3)
	7-GT	121	1633	X	X	X	X	N	N	X	X		X	N	N	1.0	.0	212	404	0	6	422	680	.39	0	.11	
EL SEGUNDO	1	175	1725											N	N	1.0	.7	270	320	26	297	565	735	2.09	3.30	2.73	
	2	175	1725											N	N	1.0	.7	270	320	22	250	565	735	2.32	3.54	2.54	
	3	330	3101	ABIS	4/24	X	X	N	L	N	N			N	N	1.5	.5	100	225	7	83	276	930	0	0	1.39	(3)
	4	330	3101	ABIS	4/24	X	X	N	L	N	N			N	N	1.5	.5	110	210	27	311	414	969	5.34	6.39	5.66	(3)
ETIWANDA	1	132	1326	ABIS	6/24	X	X	N	L	X	X		X	N	N	1.2	.0	125	190	25	285	201	336	1.67	2.53	2.14	(3)
	2	132	1326	ABIS	6/24	X	X	N	L	X	X			N	N	1.0	.5	125	195	23	262	201	345	1.13	3.02	2.51	(3)
	3	320	3040	4/24	ABIS	X	X	N	N	N	N			N	N	.5	.5	120	210	24	268	442	851	7.19	6.31	5.12	(3)
	4	320	3040	4/24	ABIS	X	X	N	N	N	N			N	N	1.5	.3	125	210	27	303	461	851	7.56	6.72	5.85	(3)
	5-GT	121	1633	X	X		X	N	N	X	X		X	N	N	.0	.0	546	495	28	326	1050	1080	.13	.13	.13	
HIGHGROVE	1	33	395											N	N	.0	.0	257	265	1	10	123	140	.08	.03	.03	
	2	33	395											N	N	.0	.0	257	265	1	7	123	140	.07	.03	.02	
	3	45	487											N	N	.0	.0	257	265	1	14	152	172	.11	.06	.05	
	4	45	487											N	N	.0	.0	257	265	3	32	152	172	.16	.03	.16	
HUNT BEACH	1	215	2043	6/24	6/24	X	X	N	L	X	X			N	N	.5	.25	185	245	27	309	458	657	4.23	4.44	4.15	(1)
	2	215	2043	6/24	6/24	X	X	N	L	X	X			N	N	.5	.5	150	300	27	305	371	617	3.68	5.83	4.33	(1)
	3	215	2043	6/24	ABIS	O	O	N	N	X	X			N	N	1.0	.25	180	245	22	253	373	667	6.59	5.75	4.59	(1)
	4	225	2138	6/24	ABIS	O	O	N	N	X	X			N	N	1.5	.19	200	300	27	309	519	855	7.25	6.12	6.59	(1)
	5-GT	121	1633	X	X	X	X	N	N	X	X		X	N	N	1.0	1.00	425	460	1	9	842	1002	.34	.03	.22	
ORMOND B.	1	750	7125	8/32	8/32	C	C	N	L	15%	15%			N	N	2.0	.50	125	225	25	298	1080	1796	13.93	19.73	16.47	(3) 630 Mx Oil
	2	750	7125	8/32	8/32	C	C	N	L	15%	15%			N	N	2.0	.25	125	225	25	298	1080	1798	17.27	16.55	15.94	(3)
MANDALAY	1	215	2020	6/24	6/24	X	X	L	L	N	N			N	N	.75	.40	200	220	26	295	480	593	1.77	3.69	3.11	(2)
	2	215	2020	6/24	6/24	X	X	L	L	N	N			N	N	1.0	.30	170	220	18	206	416	593	3.92	1.02	2.34	(2)
	5-GT	121	1633	X	X	X	X	N	N	X	X		X	N	N	.0	.0	394	450	28	326	780	980	.24	.12	.17	

Table continued on next page

Note: N = Normal plant operating procedure
    M = Modified burner pattern
BOOS = Burners out of service
ABIS = All burners in service
    L = Oversized burner tips
    X = Not applicable
    α = NO load exponent: PPM $NO, Reduced Load = PPM NO, Rated Load \left(\frac{NO, Reduced Load}{NO, Rated Load}\right)^{\alpha}$

-GT = Gas turbine units, all others are steam units

(1) NOx limited to 225 ppm on gas, 325 ppm on oil
(2) NOx limited to 250 ppm on gas or oil
(3) NOx limited to 175 ppm on gas, 225 ppm on oil

D-25

TABLE D-VI Continued

UTILITY NOx EMISSIONS SUMMARY - PROJECTION FOR 1975

Utility: Southern California Edison

Station	Unit	Rated Load MW	Rated Heat Input MKB/H	Full Load BOOS Gas	Full Load BOOS Oil	NOx Ports Open(O) Closed(C) Gas	Oil	Burner Fuel Tips Gas	Oil	Gas Recirc. Gas	Oil	Furnace Clean(C) Dirty(D) Gas	Oil	Operating Mode Gas	Oil	NOx Load Exponent α_g	α_o	Peak Load NO, PPM 3% O_2, Dry Gas	Oil	Days Per Year On Fuel Type Gas	Oil	Peak Load NOx Rate Lb NO_2/Hr Gas	Oil	Avg. Daily Avg. NOx T/D	Dec. Daily Avg. NOx T/D	Annual Avg. NOx T/D	
REDONDO B	1	70	914											N	N	1.0	.0	300	290	11	128	332	352	.48	.82	.53	
	2	70	914											N	N	1.0	.25	330	300	18	214	365	365	.29	.57	.40	
	3	70	914											N	N	1.0	.0	330	300	9	104	365	365	.51	.85	.49	
	4	70	914											N	N	1.0	.0	330	300	16	184	365	365	.57	.84	.62	
	5	175	1725											N	N	1.0	1.7	270	320	21	234	565	736	1.22	2.06	1.34	
	6	175	1725											N	N	1.0	1.7	270	320	27	310	565	736	1.75	2.54	2.06	
	7	480	4341	8/32	8/32	C	C		L		N			M	M	1.3	.12	125	225	21	234	658	1302	11.01	5.10	8.12	(3)
	8	480	4341	8/32	8/32	C	C		L	N	N			M	M	1.0	.5	125	225	25	284	658	1302	10.90	12.35	9.37	(1)
SAN BERN.	1	63	599	4/16	ABIS	X	X	N	N	X	X			N	N	.25	.25	125	215	27	312	91	172	1.46	1.50	1.38	(3)
	2	63	599	4/16	ABIS	X	X	N	N	X	X			N	N	.5	.0	125	215	22	256	120	172	1.50	1.09	1.18	(3)
																								150.0	152.6	139.6	

D-26

Note: N = Normal plant operating procedure
M = Modified burner pattern
BOOS = Burners out of service
ABIS = All burners in service
L = Oversized burner tips
X = Not applicable
α = NO load exponent: $PPM_{NO,Reduced\ Load} = (PPM_{NO,Rated\ Load})^\alpha$

-GT = Gas turbine units, all others are steam units

(1) NOx limited to 225 ppm on gas, 225 ppm on oil
(2) NOx limited to 250 ppm on gas or oil
(3) NOx limited to 125 ppm on gas, 225 on oil

TABLE D-VII

UTILITY NOx EMISSIONS SUMMARY – PROJECTION FOR 1980

Utility: Southern California Edison

Station	Unit	Rated Load MW	Rated Heat Input MKB/H	Full Load BOOS Gas	Full Load BOOS Oil	NOx Ports Open(O)/Closed(C) Gas	NOx Ports Open(O)/Closed(C) Oil	Burner Fuel Tips Gas	Burner Fuel Tips Oil	Gas Recirc. Gas	Gas Recirc. Oil	Furnace Clean(C)/Dirty(D) Gas	Furnace Clean(C)/Dirty(D) Oil	Operating Mode Gas	Operating Mode Oil	NOx Load Exponent α Gas	NOx Load Exponent α Oil	Peak Load NO, PPM 3% O₂ Dry Gas	Peak Load NO, PPM 3% O₂ Dry Oil	Days Per Year On Fuel Type Gas	Days Per Year On Fuel Type Oil	Peak Load NOx Rate Lb NO₂/Hr Gas	Peak Load NOx Rate Lb NO₂/Hr Oil	Avg. Daily Avg. NOx 7/5	Dec. Daily Avg. NOx 7/5	Annual Avg. NOx 7/5	Notes
ALAMITOS	1	175	1725	X		X		N		N				M	N	1.5	1.0	245	350	3	300	513	505	2.61	1.80	3.65	
	2	175	1725			X		N		N				N	N	1.5	1.5	245	400	3	272	513	920	1.59	5.65	4.05	
	3	320	2840	ABIS	ABIS	X	X	N	N	N	N			N	N	.25	.5	125	225	2	197	430	852	7.61	8.31	4.35	(3)
	4	320	2840	ABIS	ABIS	X	X	N	N	N	N			N	N	.25	.5	125	225	3	333	430	852	7.93	7.16	6.08	(3)
	5	480	4510	8/32	8/32	C	C	L	L	N	N			M	N	1.3	.3	125	225	3	302	683	1353	9.69	12.31	9.00	(3)
	6	480	4510	8/32	8/32	C	C	L	L	N	N			M	N	1.3	.5	125	225	3	251	683	1353	12.2	.0	7.30	(3)
	7-GT	121	1633	X	X	X	X	N	N	N	X		X	N	N	1.0	1.0	212	404	0	7	420	880	.46	.3	.14	
EL SEGUNDO	1	175	1725					N		N				N	N	1.0	1.7	270	320	3	319	565	736	3.24	5.15	3.91	
	2	175	1725					N		N				N	N	1.0	1.7	270	320	3	272	565	736	3.62	5.42	1.58	
	3	330	3101	ABIS	4/24	X	X	L	L	N	N			N	N	1.5	.5	100	225	1	99	376	830	.0	.2	1.89	(3)
	4	330	3101	ABIS	4/24	X	X	L	L	N	N			N	N	1.5	.5	110	210	3	335	414	865	6.66	7.99	7.10	(3)
ETIWANDA	1	132	1326	ABIS	6/24	X	X	L	L	X	X			N	N	1.2	.0	125	190	3	257	201	336	2.17	2.93	2.59	(3)
	2	132	1326	ABIS	6/24	X	X	L	L	X	X			N	N	1.0	.5	125	195	3	282	201	345	1.22	3.36	2.63	(3)
	3	320	3040	4/24	ABIS	X	O	N	N	N	N			N	N	.5	.5	120	210	3	288	442	851	8.01	7.98	6.12	(3)
	4	320	3040	4/24	ABIS	X	O	N	N	N	N			N	N	1.5	.3	125	210	3	329	461	851	8.10	8.15	7.25	(3)
	5-GT	121	1633	X	X	X	X	N	N	X	X		X	N	N	.0	.0	596	495	4	351	1080	1080	.15	.25	.13	
HIGHGROVE	1	33	395											N	N	.0	.0	257	265	0	11	123	140	.09	.04	.03	
	2	33	395											N	N	.0	.0	257	265	0	8	123	140	.08	.03	.03	
	3	45	487											N	N	.0	.0	257	265	0	16	152	172	.14	.07	.06	
	4	45	487											N	N	.0	.0	257	265	0	34	152	172	.13	.03	.06	
HUNT BEACH	1	215	2043	6/24	6/24	X	X	N	L	X	X			N	N	.5	.25	125	245	3	333	459	667	5.09	5.39	5.07	(2)
	2	215	2043	6/24	6/24	X	X	N	L	X	X			N	N	.5	.5	150	300	3	329	391	817	4.40	7.28	5.55	(2)
	3	215	2043	6/24	ABIS	O	O	N	N	X	X			M	N	1.0	.25	160	245	3	276	373	807	7.93	6.34	5.54	(2)
	4	225	2138	6/24	ABIS	O	O	N	N	X	X			N	N	1.5	.1	200	300	3	335	518	855	8.53	7.15	7.91	(1)
	5-GT	121	1633	X	X	X	X	N	N	N	X		X	N	N	1.0	1.0	425	460	0	11	842	1031	.41	.39	.27	
ORMOND B.	1	750	7125	8/32	8/32	C	C	N	L	15%	15%			N	M	2.0	.5	125	225	3	332	1080	1790	16.36	21.27	22.09	(3)
	2	750	7125	8/32	8/32	C	C	N	L	15%	15%			N	M	2.0	.5	125	225	3	332	1080	1738	20.31	20.31	19.01	(3)
MANDALAY	1	215	2020	6/24	6/24	X	X	L	L	N	N			M	N	.75	.4	200	220	3	319	490	593	2.19	4.55	3.44	(2)
	2	215	2020	6/24	6/24	X	X	L	L	N	N			N	N	1.0	.3	170	220	2	332	416	593	4.76	1.24	2.92	(2)
	3-GT	121	1633	X	X	X	X	N	N	N	X		X	N	N	.0	.0	394	450	4	351	780	860	.27	.14	.19	

Note: N = Normal plant operating procedure
   M = Modified burner pattern
   BOOS = Burners out of service
   ABIS = All burners in service
   L = Oversized burner tips
   X = Not applicable
   α = NO load exponent: PPM NO,Reduced Load = (PPM NO,Rated Load)^α
   -GT = Gas turbine units, all others are steam units

Table continued on next page

(1) NOx limited to 225 ppm on gas, 325 ppm on oil
(2) NOx limited to 250 ppm on gas on oil
(3) NOx limited to 125 ppm on gas, 225 on oil

D-27

TABLE D-VII Continued

UTILITY NOx EMISSIONS SUMMARY - PROJECTION FOR 1980

Utility: Southern California Edison

Station	Unit	Rated Load MW	Rated Heat Input MMB/H	Full Load BOOS Gas	Full Load BOOS Oil	NOx Ports Open(O) Closed(C) Gas	NOx Ports Oil	Burner Fuel Tips Gas	Burner Fuel Tips Oil	Gas Recirc. Gas	Gas Recirc. Oil	Furnace Clean(C) Dirty(D) Gas	Furnace Oil	Operating Mode Gas	Operating Mode Oil	NOx Load Exponent αg Gas	NOx Load Exponent αo Oil	Peak Load NO, PPM 3% O₂,Dry Gas	Peak Load Oil	Days Per Year On Fuel Type Gas	Days Oil	Peak Load NOx Rate lb NO₂/Hr Gas	Rate Oil	Aug. Daily Avg. NOx T/D	Dec. Daily Avg. NOx T/D	Annual Avg. NOx T/D	
REDONDO B.	1	70	914											N	N	1.0	.0	300	290	1	138	332	352	.56	.95	.64	
	2	70	914											N	N	1.0	.25	330	300	2	230	365	365	.34	.68	.51	
	3	70	914											N	N	1.0	.0	330	330	1	112	365	365	.59	.99	.59	
	4	70	914											N	N	1.0	.0	330	300	2	199	365	365	.60	.97	.75	
	5	175	1725											N	N	1.0	1.7	270	320	3	252	565	736	1.91	3.22	2.09	
	6	175	1725											N	N	1.0	1.7	270	320	3	334	565	736	2.73	3.97	3.15	
	7	480	4341	8/32	8/32	C	C		L	N	N			M	N	1.3	.12	125	225	3	257	658	1302	3.00	6.03	9.28	(3)
	8	480	4341	8/32	8/32	C	C	N	L	N	N			M	N	1.0	.5	125	225	4	316	658	1302	13.61	12.35	10.78	(3)
SAN BERN.	1	63	599	4/16	ABIS	X	X	N	N	X	X			M	N	.25	.25	125	215	4	242	91	172	1.67	1.67	1.60	(3)
	2	63	599	4/16	ABIS	X	X	N	N	X	X			M	N	.5	.0	125	215	3	260	120	172	1.70	1.26	1.35	(3)
LONG BEACH	GT	575	5175	X	X	X	X	X	X	X	X	X		N	N	.0	.0	(4)	(4)	3	351	770	770	6.43	6.43	6.43	(4)

189.0   189.5   179.8

Note: N = Normal plant operating procedure
M = Modified burner pattern
BOOS = Burners out of service
ABIS = All burners in service
L = Oversized burner tips
X = Not applicable
α = No load exponent: $PPM_{NO,Reduced\ Load} = PPM_{NO,Rated\ Load} \left(\frac{PPM_{NO,Reduced\ Load}}{PPM_{NO,Rated\ Load}}\right)^{\alpha}$

-GT = Gas turbine units, all others are steam units

(1) NOx limited to 225 ppm on gas, 325 ppm on oil
(2) NOx limited to 250 ppm on gas or oil
(3) NOx limited to 125 ppm on gas, 225 on oil
(4) Long Beach units limited to 140 lb/hr each for 7 gas turbines

D-28

TABLE D-VIII

UTILITY NOx EMISSIONS SUMMARY FOR 7/72 - 6/73

Utility: Los Angeles Dept. of Water and Power

Station	Unit	Rated Load MW	Rated Heat Input MBE/H	Full Load BOOS Gas	Full Load BOOS Oil	NOx Ports Open(O)/Closed(C) Gas	NOx Ports Oil	Burner Fuel Tips Gas	Burner Fuel Tips Oil	Gas Recirc. Gas	Gas Recirc. Oil	Furnace Clean(C)/Dirty(D) Gas	Furnace Oil	Operating Mode Gas	Operating Mode Oil	NOx Load Exponent αg Gas	αo Oil	Peak Load NO, PPM 3% O₂,Dry Gas	Oil	Days Per Year On Fuel Type Gas	Oil	Peak Load NOx Rate Lb NO₂/Hr Gas	Oil	Avg. Daily Avg. NOx T/D	Dec. Daily Avg. NOx T/D	Annual Avg. NOx T/D	
HARBOR	1	75	977											N	N	2.	.25	265	425	192	192	314	554	.05	.99	.??	
	2	75	977											N	N	2.	.25	265	425	162	192	314	554	.12	1.22	.95	
	3	90	1071											N	N	2.	.25	460	450	162	192	597	643	.00	2.55	1.67	
	4	90	1071											N	N	2.	.25	460	450	128	81	597	643	.31	2.73	.57	
	5	95	1134	X										N	N	2.	.25	480	450	123	142	659	690	.46	.00	.99	
	6-GT	21	283	X	X	X	X	X		X	X	X	X	N	N	0.	0.	(2)	(2)	162	192	81	137	.01	.02	.01	(2)
	7-GT	21	283	X	X	X	X	X		X	X	X	X	N	N	0.	0.	(2)	(2)	162	192	81	137	.01	.02	.01	(2)
	8-GT	21	283	X	X	X	X	X		X	X	X	X	N	N	0.	0.	(2)	(2)	162	192	81	137	.01	.02	.01	(2)
	9-GT	21	283	X	X	X	X	X		X	X	X	X	N	N	0.	0.	(2)	(2)	162	192	81	137	.01	.02	.21	(2)
HAYNES	1	242	2240	4/12	4/12	X	X	N	L	N	N	D	D	N	N	3.	.4	230	225	27	179	543	672	.0	1.63	3.24	(1)
	2	240	2221	4/12	4/12	X	X	L	L	N	N	C	C	M	M	3.	.0	85	180	125	229	229	533	1.67	5.91	3.95	(1)
	3	245	2258	2/12	ABIS	O	C	N	N	N	N	C	C	M	M	1.5	1.0	225	320	125	229	615	964	6.16	9.98	7.97	(1)
	4	245	2258	2/12	ABIS	O	C	N	N	N	N	C	C	M	M	1.5	.75	225	320	125	229	615	964	4.81	7.83	6.58	(1)
	5	350	2840	8/24	8/24	O	O	L	L	N	N	C	C	M	M	3.	1.0	225	240	125	229	775	909	3.85	7.00	5.55	(1)
	6	350	2840	8/24	8/24	O	O	L	L	N	N	C	C	M	M	2.6	1.5	210	220	125	229	723	833	6.17	6.89	5.73	(1)
VALLEY	1	100	1103	ABIS	ABIS	X	X	N	L	Below 70 NW	N	D/C	D/C	N	N	.75	.25	230	305	264	90	308	449	1.45	2.69	1.57	
	2	100	1103	ABIS	ABIS	X	X	N	L	Below 70	N	D/C	D/C	N	N	.8	.6	230	325	264	90	308	479	1.41	2.47	1.26	
	3	175	1638	ABIS	ABIS	X	X	N	L	X	X	D/C	D/C	N	N	.75	.75	225	350	264	90	447	764	1.90	5.97	3.14	
	4	175	1638	ABIS	ABIS	X	X	N	L	X	X	D/C	D/C	N	N	.25	.25	175	330	264	90	548	722	2.29	5.38	2.91	
SCATTERGOOD	1	180	1764	4/16	4/16	X	X	N	L	N	N	C	C	M	M	.9	0.	155	170	171	194	331	400	2.13	3.53	2.94	
	2	180	1764	4/16	4/16	X	X	N	L	N	N	C	C	M	M	.9	0.	155	170	53	6	331	400	.0	.0	.??	= No. Oper.

32.8   66.0   49.9

49.9

Note: N = Normal plant operating procedure
M = Modified burner pattern
BOOS = Burners out of service
ABIS = All burners in service
L = Oversized burner tips
x = Not applicable
α = NO load exponent: $PPM_{NO,Reduced\ Load} = PPM_{NO,Rated\ Load}^{\alpha}$

-GT = Gas turbine units, all others are steam units

(1) NOx limited to 225 ppm for gas, 325 ppm for oil
(2) NOx limited to 140 lb NOx as NO₂/hr
(3) See Table D-XV for data sources

D-29

TABLE D-IX

UTILITY NOx EMISSIONS SUMMARY – PROJECTION FOR 1975

Utility: Los Angeles Dept. of Water and Power

Station	Unit	Rated Load MW	Rated Heat Input KMB/H	Full Load BCOS Gas	Oil	NOx Ports Open(O) Closed(C) Gas	Oil	Burner Fuel Tips Gas	Oil	Gas Recirc. Gas	Oil	Furnace Clean(C) Dirty(D) Gas	Oil	Operating Mode Gas	Oil	NOx Load Exponent cg	co Oil	Peak Load NO, PPM 3% O₂, Dry Gas	Oil	Days Per Year On Fuel Type Gas	Oil	Peak Load NOx Rate lb NO2/hr Gas	Oil	Avg. Daily Avg. NOx T/D	Dec. Daily Avg. NOx T/D	Annual Avg. NOx T/D	
HARBOR	1	75	977											N	N	2.	.25	265	425	0	0	314	554	.0	.0	.0	Standby
	2	75	977											N	N	2.	.25	265	425	0	0	314	554	.0	.0	.0	"
	3	90	1071											N	N	2.	.25	460	450	0	0	597	643	.0	.0	.0	"
	4	90	1071											N	N	2.	.25	460	450	0	0	597	643	.0	.0	.0	"
	5	95	1134											N	N	2.	.25	480	450	0	0	660	680	.0	.0	.0	"
	6-GT	21	283		X		X		N		X		X		N	.0	.0	(2)	(2)	0	0	80.6	136.9	.0	.0	.0	(2)"
	7-GT	21	.283		X		X		N		X		X		N	.0	.0	(2)	(2)	0	0	80.6	136.8	.0	.0	.0	(2)"
	8-GT	21	283		X		X		N		X		X		N	.0	.0	(2)	(2)	0	0	80.6	136.8	.0	.0	.0	(2)"
	9-GT	21	283		X		X		N		X		X		N	.0	.0	(2)	(2)	0	0	80.6	136.8	.0	.0	.0	(2)"
HAYNES	1	242	2240	4/12	4/12	X	X	L	N	N	N			M	M	.0	.4	125	225	10	195	340	672	.0	1.12	2.30	(1)
	2	240	2221	4/12	4/12	X	X	L	L	N	N			M	M	3.	.0	85	180	18	336	229	533	4.22	4.51	3.72	(1)
	3	245	2258	2/12	ABIS	O	C	N	N	N	N			M	M	.0	.0	125	225	18	336	342	677	5.67	5.69	5.30	(1)
	4	245	2258	2/12	ABIS	O	C	N	N	N	N			M	M	.0	.0	125	225	18	336	342	677	5.14	4.91	4.62	(1)
	5	350	2840	8/24	8/24	(3)	(3)	L	L	N	N			M	M	.0	.0	125	225	18	336	430	852	6.13	6.16	5.70	(1)
	6	350	2840	8/24	8/24	O	O	L	L	N	N			M	M	.0	.0	125	220	18	336	430	833	6.80	6.46	5.79	(1)
VALLEY	1	100	1103	ABIS	ABIS	X	X	N	L	N	N			M	M	.75	.25	230	305	18	336	308	449	1.96	1.92	1.70	
	2	100	1103	ABIS	ABIS	X	X	N	L	N	N			M	M	.8	.5	230	325	18	336	309	478	1.71	1.65	1.25	
	3	175	1638	ABIS	ABIS	X	X	N	L	X	X			M	M	.75	.25	225	350	18	336	447	764	3.08	4.27	3.55	
	4	175	1638	ABIS	ABIS	X	X	N	L	X	X			M	M	.25	.25	175	330	18	336	247	721	3.41	3.85	3.36	
SCATTERGOOD	1	180	1764	4/16	4/16	X	X	N	L	N	N			N	N	.9	.0	155	170	18	336	331	400	2.60	2.70	2.64	12 Mo. Oper
	2	180	1764	4/16	4/16	X	X	N	L	N	N			N	N	.9	.0	155	170	18	336	331	400	2.60	2.70	2.64	(1)Gas Only
	3	490	4410		X		X		X		X		X		X	0	X	(2)	X	0	0	140	X	.0	.0	.0	(Standby)
																								43.3	45.9	42.6	

Note: N = Normal plant operating procedure
M = Modified burner pattern
BCOS = Burners out of service
ABIS = All burners in service
L = Oversized burner tips
X = Not applicable
α = NO load exponent: $PPM_{NO,Reduced\ Load} = (PPM_{NO,Rated\ Load})^{\alpha}$

-GT = Gas turbine units, all others are steam units

(1) NOx limited to 125 ppm for gas, 225 ppm for oil
(2) NOx limited to 140 lb NOx as NO2/hr
(3) NOx ports doubled in size (Haynes 3)

All Haynes units to have air preheat bypass

D-30

TABLE D-X

UTILITY NOX EMISSIONS SUMMARY - PROJECTION FOR 1980

Utility: Los Angeles Dept. of Water and Power

Station	Unit	Rated Load MW	Rated Heat Input MBH/H	Full Load BOOS Gas	Oil	NOx Ports Open(O) Closed(C) Gas	Oil	Burner Fuel Tips Gas	Oil	Gas Recirc. Gas	Oil	Furnace Clean(C) Dirty(D) Gas	Oil	Operating Mode Gas	Oil	NOx Load Exponent eg. α Gas	Oil	Peak Load NO, PPM 3% O_2, Dry Gas	Oil	Days Per Year Ca Fuel Type Gas	Oil	Peak Load NOx Rate Lb NO_2/Hr Gas	Oil	Avg. Daily Avg. NOx 7/5	Dec. Daily Avg. NOx 7/5	Annual Avg. NOx 7/5	
HARBOR	1	75	977											N	X	2.	.25	265	425	0	0	314	554	.0	.0	.0	standby
	2	75	977											N	X	2.	.25	265	425	0	0	314	554	.0	.0	.0	"
	3	90	1071											N	X	2.	.25	265	450	0	0	597	643	.0	.0	.0	"
	4	90	1071											N	X	2.	.25	265	450	0	0	597	643	.0	.0	.0	"
	5	95	1134	X										N	X	2.	.25	265	450	0	0	660	630	.0	.0	.0	"
	6-GT	21	283	X	X	X	X	N	N	X	X		X	N	N	.0	.0	(2)	(2)	0	0	81	137	.0	.0	.0	(2)"
	7-GT	21	283	X	X	X	X	N	N	X	X		X	N	N	.0	.0	(2)	(2)	0	0	81	137	.0	.0	.0	(2)"
	8-GT	21	283	X	X	X	X	N	N	X	X		X	N	N	.0	.0	(2)	(2)	0	0	81	137	.0	.0	.0	(2)"
	9-GT	21	283	X	X	X	X	N	N	X	X		X	N	N	.0	.0	(2)	(2)	0	0	81	137	.0	.0	.0	(2)"
HAYNES	1	242	2240	4/12	4/12	X	X	N	L	N	N			X	X	.0	.4	125	225	0	206	340	672	.0	1.26	2.64	(1)
	2	240	2221	4/12	4/12	X	X	L	L	N	N			X	N	3.	.0	85	180	0	354	229	533	4.59	4.91	4.23	(1)
	3	245	2258	2/12	ABIS	O	C	N	N	N	N			X	N	.0	.0	125	225	0	354	342	678	6.17	6.19	5.92	(1)
	4	245	2258	2/12	ABIS	O	C	N	N	N	N			X	N	.0	.0	125	225	0	354	342	678	5.59	5.34	5.16	(1)
	5	350	2840	8/24	8/24	(3)	(3)	L	L	X	X			X	X	.0	.0	125	225	0	354	430	852	6.67	6.71	6.35	(3)
	6	350	2840	8/24	8/24	O	O	L	L	X	X			X	X	.0	.0	125	225	0	354	430	833	7.46	7.00	6.46	(1)
VALLEY	1	100	1103	ABIS	ABIS	X	X	N	L	N	N			X	X	.75	.25	230	305	0	354	308	449	2.19	2.14	1.95	
	2	100	1103	ABIS	ABIS	X	X	N	L	N	N			N	X	.8	.5	230	325	0	354	308	475	1.94	1.86	1.46	
	3	175	1638	ABIS	ABIS	X	X	N	L	X	X			N	N	.75	.25	225	350	0	354	447	764	3.42	4.74	4.06	
	4	175	1638	ABIS	ABIS	X	X	N	L	X	X			N	N	.25	.25	175	330	0	354	347	721	3.78	3.27	3.84	
SCATTERGOOD	1	180	1764	4/16	4/16	X	X	N	L	N	N			N	X	.9	.0	155	170	4	361	331	500	2.83	2.92	2.94	
	2	180	1764	4/16	4/16	X	X	N	L	N	N			N	X	.9	.0	155	170	4	361	331	400	2.83	2.93	2.94	
	3	490		X		X	X		X		X		X	X	X	.0	X	(2)	X	365	0	140	X	.0	.0	.0	(2) Gas Only (standby)
																								47.4	50.3	47.9	

D-31

Note:
- N = Normal plant operating procedure
- M = Modified burner pattern
- BOOS = Burners out of service
- ABIS = All burners in service
- L = Oversized burner tips
- X = Not applicable
- o = NO load exponent: PPM $_{NO}$,Reduced Load = PPM $_{NO}$,Rated Load (PPM $_{NO}$,Reduced Load $\div$ PPM $_{NO}$,Rated Load)$^\alpha$

-GT = Gas turbine units, all others are steam units

(1) NOx limited to 125 ppm for gas, 225 ppm for oil
(2) NOx limited to 140 lb NOx as NO_2/hr
(3) NOx ports doubled in size (Haynes 3)

All Haynes units to have air preheat bypass

TABLE D-XI

UTILITY NOx EMISSIONS SUMMARY

Utility: Burbank Public Service

Station	Unit	Rated Load MW	Rated Heat Input MMB/H	Full Load BOOS Gas	Oil	NOx Ports Open(O) Closed(C) Gas	Oil	Burner Fuel Tips Gas	Oil	Gas Recirc. Gas	Oil	Furnace Clean(C) Dirty(D) Gas	Oil	Operating Mode Gas	Oil	NOx Load Exponent αg Gas	αo Oil	Peak Load NO PPM 3% O2,Dry Gas	Oil	Days Per Year On Fuel Type Gas	Oil	Peak Load NOx Rate lb NO2/Hr Gas	Oil	Avg. Daily Avg. NOx T/D	Dec. Daily Avg. NOx T/D	Annual Avg. NOx T/D
STATUS FOR 1973 (7/72 – 6/73)																										
MAGNOLIA	1	10	158	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	322	429	56	63	62	90	.001	.0	.002
	2	10	158	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	322	429	56	63	62	90	.021	.0	.002
	3	10	158	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	322	429	93	172	62	90	.07	.04	.04
	4	20	315	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	273	488	114	240	104	205	.14	.22	.21
	5-GT	22	293	x	x	x	x	N	N	x	x	X	X	N	H	.0	.0	325	540	96	198	115	204	.002	.005	.012
OLIVE	1	44	491	ABIS	ABIS	x	x	N	N	x	x	C	C	N	N	.0	.0	302	434	114	240	180	284	.52	.82	.68
	2	60	567	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.5	140	250	114	240	96	189	.60	1.10	.91
	3-GT	21	283	x	x	x	x	N	N	x	x	X	X	N	N	.0	.0	306	382	95	229	105	144	.04	.04	.09
																								1.4	2.2	1.9
PROJECTION FOR 1975																										
MAGNOLIA	1	10	158	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	322	429	12	107	62	90	.002	.0	.003
	2	10	158	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	322	429	12	107	62	90	.002	.0	.003
	3	10	158	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	322	429	27	238	62	90	.11	.05	.04
	4	20	315	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	273	488	36	319	104	205	.30	.24	.26
	5-GT	22	293	x	x	x	x	N	N	x	x	X	X	N	N	.0	.0	325	540	30	266	115	204	.004	.006	.02
OLIVE	1	44	491	ABIS	ABIS	x	x	N	N	x	x	C	C	N	N	.0	.0	302	434	35	319	180	284	.91	.90	.82
	2	60	567	ABIS	ABIS	x	x	N	N	x	x	C	C	N	N	.0	.5	140	250	35	319	96	189	1.00	1.27	1.13
	3-GT	21	283	x	x	x	x	N	N	x	x	X	X	N	N	.0	.0	306	382	32	292	105	144	.05	.04	.10
	4-GT	32	352	x	x	x	x	N	N	x	x	X	X	N	N	.0	.0	(1)	(1)	35	319	140	140	.19	.19	.19
																								2.6	2.7	2.6
PROJECTION FOR 1980																										
MAGNOLIA	1	10	158	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	322	429	1	118	62	90	.003	.0	.003
	2	10	158	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	322	429	1	118	62	90	.003	.0	.003
	3	10	158	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	322	429	3	262	104	205	.14	.06	.05
	4	20	315	ABIS	ABIS	x	x	N	N	x	x	D	D	N	N	.0	.0	273	465	4	351	104	205	.37	.30	.33
	5-GT	22	293	x	x	x	x	N	N	x	x	X	X	N	N	.0	.0	325	540	3	293	115	204	.005	.007	.02
OLIVE	1	44	491	ABIS	ABIS	x	x	N	N	x	x	C	C	N	N	.0	.0	302	434	4	351	180	284	1.11	1.10	1.04
	2	60	567	ABIS	ABIS	x	x	N	N	x	x	C	C	N	N	.0	.5	140	250	4	351	96	189	1.34	1.71	1.55
	3-GT	21	283	x	x	x	x	N	N	x	x	X	X	N	N	.0	.0	306	362	3	321	105	144	.07	.05	.13
	4-GT	32	352	x	x	x	x	N	N	x	x	X	X	N	N	.0	.0	(1)	(1)	4	351	140	140	.23	.23	.23
																								3.3	3.5	3.4

(1) On line 1974

Note: N = Normal plant operating procedure
M = Modified burner pattern
BOOS = Burners out of service
ABIS = All burners in service
L = Oversized burner tips
X = Not applicable
α = NO load exponent: $PPM_{NO,Reduced\ Load} = PPM_{NO,Rated\ Load}(\frac{Reduced\ Load}{Rated\ Load})^{\alpha}$
-GT = Gas turbine units, all others are steam units

(1) NOx limited to 140 lb NOx as NO_2/hr
(2) See Table D-XVI for data sources
* Unit tested in PPM/A&B program

D-32

TABLE D-XII

UTILITY NOx EMISSIONS SUMMARY

Utility: Glendale Public Service

Station	Unit	Rated Load MW	Rated Heat Input KWB/H	Full Load BOOS Gas	Oil	NOx Ports Open(O) Closed(C) Gas	Oil	Burner Fuel Tips Gas	Oil	Gas Recirc. Gas	Oil	Furnace Clean(C) Dirty(D) Gas	Oil	Operating Mode Gas	Oil	NOx Load Exponent α₀ Gas	Oil	Peak Load NOx PPM 3% O₂ Dry Gas	Oil	Days Per Year On Fuel Type Gas	Oil	Peak Load NOx Rate lb NOx/Hr Gas	Oil	Avg. Daily Avg. NOx T/D	Dec. Daily Avg. NOx T/D	Annual Avg. NOx T/D	
STATUS FOR 7/72 - 6/73																											
GLENDALE	1A	20	252	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	250	253	126	229	76	95	.09	.37	.25	
	1B	20	252	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	250	284	126	228	76	95	.09	.41	.27	
	2	20	252	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	250	279	126	228	76	94	.09	.40	.27	
	3	20	265	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	250	392	126	228	80	139	.10	.60	.39	
	4	44	491	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	250	285	126	228	149	187	.18	.90	.54	
	5	44	491	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	130	270	126	228	77	177	.09	.75	.48	
	6-GT	21	284	X	X	X	X	N	N	X	X	X		N	N	1	0	(2)	(2)	126	228	140	140	.10	.16	.14	(2)
																								.7	3.5	2.3	
PROJECTION FOR 1975																											
GLENDALE	1A	20	252	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	250	253	35	318	76	85	.30	.34	.28	
	1B	20	252	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	250	284	35	318	76	95	.33	.38	.32	
	2	20	252	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	250	279	35	318	76	94	.32	.37	.31	
	3	20	265	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	250	392	35	318	80	139	.48	.55	.45	
	4	44	491	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	250	295	35	318	149	187	.65	.74	.62	
	5	44	491	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0	130	270	35	318	77	177	.61	.70	.58	
	6-GT	21	284	X	X	X	X	N	N	X	X	X	X	N	N	1	0	(2)	(2)	35	318	140	140	.16	.18	.17	(2)
	7-GT	31	419	X	X	X	X	N	N	X	X	X	X	N	N	1	0	(2)	(2)	35	318	140	140	.19	.19	.19	(2)On line 1974
																								3.1	3.5	2.9	
PROJECTION FOR 1982																											
GLENDALE	1A																									X	(3)
	1B																									X	(3)
	2																									X	(1)
	3	20	265	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0			4	351	80	139	.57	.66	.59	
	4	44	491	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0			4	351	149	187	.77	.89	.79	
	5	44	491	ABIS	ABIS	X	X	N	N	X	X			N	N	1	0			4	351	77	177	.73	.84	.75	
	6-GT	21	284	X	X	X	X	N	N	X	X	X	X	N	N	1	0	(2)	(2)	4	351	140	140	.22	.22	.22	(2)
	7-GT	31	419	X	X	X	X	N	N	X	X	X	X	N	N	1	0	(2)	(2)	4	351	140	140	.23	.23	.23	(2)
	8-GT	30	310	X	X	X	X	N	N	X	X	X	X	N	N	1	0	(2)	(2)	3	349	140	140	.22	.22	.22	(2)On line 1974
																								2.7	3.1	2.8	

Note: N = Normal plant operating procedure
M = Modified burner pattern
BOOS = Burners out of service
ABIS = All burners in service
L = Oversized burner tips
X = Not applicable
α = NO load exponent: PPM $\propto$ PPM$\left(\frac{NO_x \text{ Reduced Load}}{NO_x \text{ Rated Load}}\right)^\alpha$

-GT = Gas turbine units, all others are steam units

(1) Units 1A, 1B, 2 replaced by Unit 8
(2) Units limited to 140 lb NO₂/hr
(3) See Table D-XVI for data sources.

TABLE D-XIII

UTILITY NOx EMISSIONS SUMMARY

Utility: Pasadena Dept. of Water and Power

Station	Unit	Rated Load MW	Rated Heat Input KKB/H	Full Load BOOS Gas	Oil	NOx Ports Open(O) Closed(C) Gas	Oil	Burner Fuel Tips Gas	Oil	Gas Recirc. Gas	Oil	Furnace Clear(C) Dirty(D) Gas	Oil	Operating Mode Gas	Oil	NOx Load Exponent αg Gas	αo Oil	Peak Load NO,PPM 3% O2 Dry Gas	Oil	Days Per Year On Fuel Type Gas	Oil	Peak Load NOx Rate lb NO2/hr Gas	Oil	Avg. Daily Avg. NOx T/D	Dec. Daily Avg. NOx T/D	Annual Avg. NOx T/Y
STATUS FOR 1973 (7/72 - 6/73)																										
BROADWAY	B1	45	529	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1.5	.3	330	350	78	198	212	247	.23	1.44	.87
	B2	45	529	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1.5	.3	300	420	70	166	192	296	.32	.66	.97
	B3	70	693	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	.7	.3	320	260	98	248	264	240	1.38	2.08	1.79
GLENARM	G9	45	526	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1	0	250	250	57	30	159	175	.01	.0	.10
	G8	20	600	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1	0	250	250	2	3	182	200	.0	.0	.008
																								1.9	4.2	3.6
PROJECTION FOR 1975																										
BROADWAY	B1	45	529	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1.5	.3	330	350	27	244	212	247	.99	1.65	1.14
	B2	45	529	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1.5	.3	300	420	23	211	192	296	1.34	.74	1.08
	B3	70	693	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	.7	.3	320	260	34	302	269	240	1.71	2.33	2.00
GLENARM	G9	45	526	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1	0	250	250	8	76	159	175	.05	.0	.17
	G8	20	600	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1	0	250	250	1	4	182	200	.0	.0	.01
																								4.0	4.7	4.4
PROJECTION FOR 1980																										
BROADWAY	B1	45	529	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1.5	.3	330	350	3	273	212	247	1.16	2.11	1.48
	B2	45	529	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1.5	.3	300	420	2	233	192	296	1.73	.96	1.41
	B3	70	693	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	.7	.3	320	260	4	342	269	240	2.21	2.33	2.14
GLENARM	G9	45	526	ABIS	ABIS	X	X	N	N	X	X	C	C	N	N	1	0	250	250	1	86	159	175	.05	.0	.78
	G8	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
	GT	73	657	X	X	X	X	N	N	X	X	X	X	N	N	1	0	(1)	(1)	X	3	140	140	1.17	1.17	1.17
																								6.3	6.6	6.4

(1) Glenarm, G8, replaced by Gas Turbine in 1976, NO limited to 140 lb NO2/hr

(2) See Table D-XVI for data sources

Note:
N = Normal plant operating procedure
M = Modified burner pattern
BOOS = Burners out of service
ABIS = All burners in service
L = Oversized burner tips
X = Not applicable
α = NO load exponent: $PPM_{NO,Reduced\ Load} = (PPM_{NO,Rated\ Load})^\alpha$

-GT = Gas turbine units, all others are steam units

TABLE D-XIV

COMPARISON OF DATA SOURCES

Utility Boiler Peak Load NO, ppm at 3% O_2, Dry

UTILITY: SCE

Station	Unit	Rated Load Mw	LA APCD (1)		Calif. ARB (2)		Utility (7/72 - 6/73)		Other		Data Taken From Similar Unit
			Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	
ALAMITOS	1	175	245*	310	229	207	-	350*			
	2	175	245*	310	229	207	-	400*			
	3	320	110	210	-	-	200*	230*			*Alamitos 3
	4	320	110	210	-	-	-	-			*Gas - Redondo 7
	5	480	150	235	-	-	-	320*			*Alamitos 5
	6	480	150	235	-	-	-	-			
	7-GT	121	-	-	212*	404*	-	-			
EL SEGUNDO	1	175	300	210	297	207	-	-			*Redondo 5
	2	175	300	210	297	207	220	210			*Redondo 5
	3	330	110	210	-	-	100*	245*			
	4	330	110*	210*	-	-	-	-			
ETIWANDA	1	132	-	-	169	251	200*	190*			
	2	132	-	-	169	251	230*	195*			
	3	320	-	-	-	-	120*	210*			
	4	320	-	-	-	-	140*	210*			
	5-GT	121	-	-	546*	495*	-	-			
HIGHGROVE	1	33	-	-	257*	265*	-	-			
	2	33	-	-	257*	265*	-	-			
	3	45	-	-	257*	265*	-	-			
	4	45	-	-	257*	265*	-	-			
HUNT BEACH	1	215	-	-	229	290	185*	245*			
	2	215	-	-	229	290	150*	300*			
	3	215	-	-	193	203	180*	245*			
	4	225	-	-	209	208	200*	300*			
	5-GT	121	-	-	425*	460*	-	-			

D-35

TABLE D-XIV Continued

COMPARISON OF DATA SOURCES

Utility Boiler Peak Load NO, ppm at 3% O_2, Dry

UTILITY: SCE

Station	Unit	Rated Load Mw	LA APCD (1)		Calif. ARB (2)		Utility (7/72 - 6/73)		Other		Data Taken From Similar Unit
			Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	
ORMOND BEACH	1	750	-	-	-	-	250*	245*			
	2	750	-	-	-	-	-	220*			*Gas - Ormond 2
MANDALAY	1	215	-	-	223	294	200*	220*			
	2	215	-	-	223	294	170*	220*			
	3-GT	121	-	-	394*	450*	-	-			
REDONDO B.	1	70	500	350	400	650	-	-	300(3)*	290(3)*	
	2	70	500	350	400	650	-	-	330(3)*	300(3)*	
	3	70	500	350	400	650	-	-			*Redondo 2
	4	70	500	350	400	650	-	-			*Redondo 2
	5	175	300	210	297	207	-	-	270(3)*	320(3)*	
	6	175	300	210	297	207	-	-			*Redondo 5
	7	480	150	235	-	-	170*	225*			
	8	480	150	235	-	-	145*	240*			
SAN BERN.	1	63	-	-	143	249	125*	215*			
	2	63	-	-	143	249	165*	215*			

*Indicates value selected for 7/72 - 6/73 Inventory (Table D-V)

(1) LA APCD, 1/72 (Reference 47)

(2) Brattain & Lemmon, ARB 12/72 (Reference 48)

(3) Tested by KVB during ARB NOx Study

D-36

TABLE D-XV

COMPARISON OF DATA SOURCES

Utility Boiler Peak Load NO, ppm at 3% O_2, Dry

UTILITY: LADWP

Station	Unit	Rated Load Mw	LA APCD (1) Gas	LA APCD (1) Oil	Calif. ARB (2) Gas	Calif. ARB (2) Oil	Utility (7/72 – 6/73) Gas	Utility (7/72 – 6/73) Oil	Other Gas	Other Oil	Data Taken From Similar Unit
HARBOR	1	75	265*	425*	483	590					
	2	75	265*	425*	483	590					
	3	90	460*	450*	525	635					
	4	90	460*	450*	525	635					
	5	95	480*	450*	525	635					
	6-GT	21	–	–	173	346					*Harbor 8
	7-GT	21	–	–	173	346					*Harbor 8
	8-GT	21	–	–	173	346	234*	362*			
	9-GT	21	–	–	173	346					*Harbor 8
HAYNES	1	242	130	270	–	–	200*	225*			
	2	240	110	250	–	–	85*	180*			
	3	245	200	300	–	–	225*	320*			
	4	245	200	300	–	–	225*	320*			
	5	350	225	270	–	–	225*	240*			
	6	350	–	270	–	–	210*	220*			
VALLEY	1	100	160	355	125	355	230*	305*			
	2	100	160	355	125	355	230*	325*			
	3	175	190	485	177	485	225*	350*			
	4	175	190	485	177	485	175*	330*			
SCATTERGOOD	1	180	150	210	142	255	155*	170*			
	2	180	150	210	142	255	155*	170*			

*Indicates value selected for 7/72 – 6/73 Inventory (Table D-VIII)

(1) LA APCD Report, 1/72 (Reference 47)

(2) Brattain & Lennon, ARB, 12/72 (Reference 48)

D-37

COMPARISON OF DATA SOURCES

Utility Boiler Peak Load NO, ppm at 3% O_2, Dry

Station	Unit	Rated Load Mw	LA APCD (1) Gas	Oil	Calif. ARB (2) Gas	Oil	Utility (7/72 - 6/73) Gas	Oil	Other Gas	Oil	Data Taken From Similar Unit
BURBANK PUBLIC SERVICE											
MAGNOLIA	1	10	250	250	250	250	322*	429*			
	2	10	250	250	250	250	322*	429*			
	3	10	250	250	250	250	322*	429*			
	4	20	250	250	250	250	273*	488*			
	5-GT	22	250	250	250	250	325*	540*			
OLIVE	1	44	90	250	90	250	302*	434*			
	2	60	195	160	195	160	237	176	140(3)*	250(3)*	
	3-GT	21					306*	382*			
GLENDALE PUBLIC SERVICE											
GLENDALE	1A	20	250	250	250*	250		253*			
	1B	20	.250	250	250*	250		284*			
	2	20	250	250	250*	250		279*			
	3	20	250	250	250*	250		392*			
	4	44	250	250	250*	250		285*			
	5	44	130	155	130*	155		270*			
PASADENA DEPT. OF WATER AND POWER											
BROADWAY	B1	45	210	250	210	250	330*	350*			
	B2	45	210	250	210	250	300*	420*			
	B3	70	250	205	250	205	320*	260*			
GLEN ARM	G9	45	-	-	-	-	-	-			* Assumed 250 ppm
	G8	20	-	-	-	-	-	-			* Assumed 250 ppm

*Indicates value selected for 7/72 - 6/73 Inventory (Tables D-XI, D-XII, D-XIII)

(1) LA APCD Report 1/72 (Reference 47)
(2) Brattain & Lemmon 12/72 (Reference 48)
(3) Tested by KVB during ARB NOx Study

D-4   <u>ELECTRIC UTILITY GENERATION REDUCTION POTENTIAL</u>

In considering the potential for reduction of NOx emissions from electric utility power plants it is important to begin with an historical perspective. The first regulation in the Basin to have an important impact on NOx emission was the implementation of rule 62 to limit sulfur content of oil burned during the months of April through November to 0.5% sulfur. Because high sulfur oil also usually contains a high fraction of fuel bound nitrogen, the restriction on its use had a significant effect on the trend in NOx with time in the Basin as can be seen in Figure D-6. By 1965 the reduction in emissions averaged over the year was approximately 150 tons/ day from the average use of about 35,000 barrels per day of low sulfur oil. At a premium for low sulfur oil which at that time was about 50¢/barrel, the cost effectiveness of this strategy worked out to be about 17 lbs of NOx prevented per dollar extra fuel cost. In addition about another 20 lbs of sulfur oxides were prevented for the same dollar spent for premium for low sulfur oil.

The next major event that reduced oxides of nitrogen was the increase in natural gas supply in 1965-66 which also drove total NOx emissions in the Basin sharply downward. Since this reduction came with a savings in cost due to slightly lower gas cost than oil, this was a very cost effective move, just as it would be today if more natural gas could be made available to the power plants (see discussion in Section 11).

By about 1969 the annual average NOx emissions in the Basin from combustion of fuels again began to climb upward. It was about this time that major implementation programs to reduce the power plant NOx emissions were initiated by Southern California Edison and Los Angeles Department of Water and Power. At the beginning of these programs the Basin-wide NOx emissions from power plants was about 290 tons/day annual average. By 1971 these emissions had been cut by over a factor of two by implementation of combustion modifications in most of the large plants. The reductions were achieved primarily with the use of low excess air operation and staged
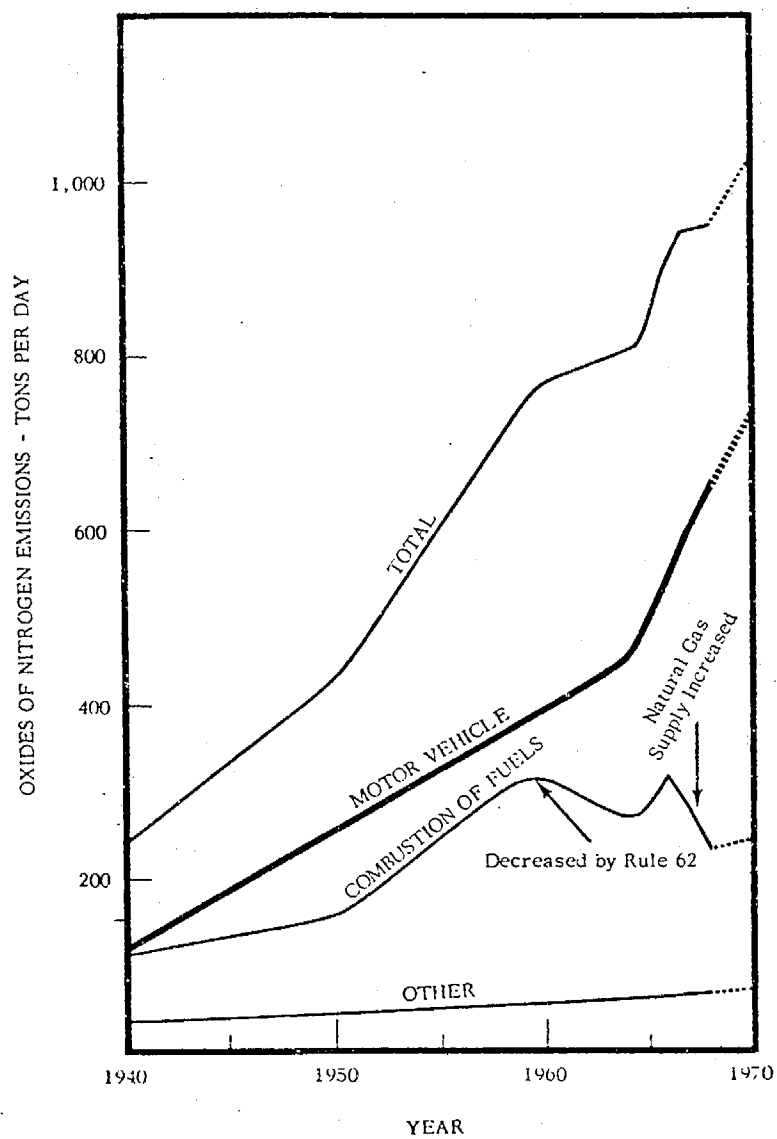
Figure D-6. Average Emissions Of Oxides Of Nitrogen In Tons Per Day From Major Contributing Sources In Los Angeles County[60]

5800-179

combustion, the principles of which were discussed in Section 2.3 and the costs
in Section 11,3,4. It is significant to note that by January 1972 the
weighted average emission concentration of NOx when burning gas was reduced
from about 500 ppm, its 1969 level, to about 200 ppm. Over the same period
weighted average emissions concentrations from low sulfur oil burning had
been reduced from 310 to about 275 ppm. Because of the nature of oil
combustion, the reduction techniques were found to be much less effective
than for gas combustion. By the period July 1972 - June 1973, the period
of the present inventory, the Basin-wide power plant NOx emissions had begun
to climb upward again because of the shift from gas to oil as indicated in
Table D-XVII.

It is of interest to examine the cost effectiveness of the reductions
from 1969 to 1972-73, when regulations on large units became effective at
325 ppm NOx as NO_2 for oil firing and 225 ppm for gas firing. To make a
valid comparison it is necessary to factor out growth in system electrical
load and shifts in the balance between oil and gas burning. Thus the emissions
have been normalized to the 1972-73 generation rates, and have been figured
separately for the hypothetical limiting situations of all energy supplied
as gas, and all supplied as oil. The results are presented in Tables D-XVIII
and D-XIX respectively. Based on all gas burning the reduction from 1969 to
1972-73 is 185 tons/day annual average. The cost of this reduction, including
engineering costs, equipment costs, and fuel costs conservatively set at
$0.50/MMB was about $0.8 million per year (see further discussion on costs
in Section 11,3,4). On this basis the reduction was a very cost effective
165 lbs of NOx prevented per dollar annualized cost. Because of the lower
effectiveness of the combustion modification for oil combustion, the cost
effectiveness figured for all oil burning Table D-XIX would be a more modest
16 lbs of NOx prevented per dollar annualized cost. The actual cost
effectiveness fell between these limits and varied each year as the shift
from gas to oil progressed, as the load changed, and as fuel costs escalated.

The next major milestone in the program of regulation of large power
plants becomes effective at the beginning of 1975 when the oil emission limit

TABLE D-XVII

SOUTH COAST AIR BASIN

ELECTRIC UTILITIES ENERGY CONSUMPTION[†]

AND FRACTION DERIVED FROM OIL FUEL

Year	Total Energy 10^{12} Btu	Energy % From Oil Fuel
69	472	19.0
70	502	22.1
71	514	40.5
72	532	42.2
Inventory Period →	535	57
73	562	69.4
74*	565	83.1
75*	614	93.6
76*	617	95.2
77*	628	98.4
78*	682	90.5
79*	725	91.1
80*	733	90.8

[†]Source: Reference 34 for sum of energy use by SCE, DWP. Other municipal utilities estimated at constant 4.4% of Basin total, the fraction for July '72 – July '73.

*Estimate from Reference 34

5800-179

TABLE D-XVIII

SOUTH COAST AIR BASIN NOx EMISSIONS

FROM ELECTRIC UTILITY POWER PLANTS

NORMALIZED TO 1972-73 GENERATION RATES

FOR OPERATION ON NATURAL GAS FUEL ONLY

	1969	1972-73	1975
Concentration limit, ppm		225	125
Limit of units controlled* MMB/H		1775	1775
NOx emissions average tons/da	310	125	88
Change in emissions average tons/da	base	185	37
Estimated annual cost for change, millions of dollars	base	0.82[†]	4.6[†]
Cost effectiveness ratio lbs NOx/$	base	165	5.9

*LA County, (see Table D-I for other counties)

[†]based on fuel cost of $.50/MMB

5800-179

TABLE D-XIX

SOUTH COAST AIR BASIN NOx EMISSIONS

FROM ELECTRIC UTILITY POWER PLANTS

NORMALIZED TO 1972-73 GENERATION RATES

FOR OPERATION ON LOW SULFUR OIL FUEL ONLY

	1969	1972-73	1975	1975
Concentration limit, ppm		325	225	225
Limit of units controlled,* MMB/H		1775	1775	1500
NOx emissions, average tons/da	230	204	190	181
Change in emissions, average tons/da	base	26	14	9
Estimated annual cost for change, millions of dollars	base	1.2**	6.6†	2.7††
Cost effectiveness ratio lbs NOx/$	base	16	1.5	2.4

*LA County, (see Table D-I for other counties)

**based on fuel cost of $1/MMB

†based on fuel cost of $2/MMB

††based on fuel cost of $2/MMB, 2 units requiring flue gas recirculation

is set at 225 ppm and gas at 125 ppm. Since a number of the units when
firing oil were already quite a bit below the 325 ppm limit in 1972-73,
the net reduction for all oil firing in 1975 compared with that in 1972-73
is seen to be only 14 tons/day in Table D-XIX. In order to achieve this,
more extensive use of staged combustion, and the installation of flue gas
recirculation is required in some of the larger units. Even reduced air
preheat is under consideration to meet the regulation for some of the
boilers. Because of the high cost of flue gas recirculation hardware and
the energy efficiency losses from recirculation, staged combustion, and
air preheat reduction coupled with higher fuel costs (about $2/MMB), the
annualized cost of attaining the reduction from '72-'73 to '75 is estimated
at about $6.6 million dollars/year. As a consequence the cost effectiveness
of this reduction is diminished to about 1.5 lb NOx as NO_2 prevented
per dollar annualized cost. Even though the same modifications will result
in larger reductions for all gas fuel operation (Table XVIII), the small
fraction of gas fuel expected to be available in 1975 will result in the
actual cost effectiveness ratio being below 2.0.

Finally one additional reduction option is considered, that is the
lowering of the size cut off for regulation down to 1500 MMB/H throughout
the Basin. This would bring an additional 14 units (representing 2630 Mw)
under the 225 ppm regulation and would reduce the Basin emissions by an
additional 9 tons/day for all oil burning operation. Based on the estimate
that only 2 of these units would require flue gas recirculation to make
this limit the cost effectiveness for this reduction is about 2.5 lbs of
NOx prevented per dollar annualized cost. This ratio could go lower if it
turns out that more units than estimated require flue gas recirculation.
Since several units are believed to be on the borderline of making the
regulation it is difficult to determine for sure how many will actually
require recirculation.

From considerations such as these it is evident that any significant
reduction in power plant NOx emissions below the 1975 projected levels will
be achievable only at much lower cost effectiveness than 1 lb per dollar.

Reducing the control limits to still lower sized units will not be cost effective due to the disproportionately large fixed initial costs and the low capacity factors at which the smaller units are operated.

D-5   CONCLUSIONS

Utility boilers which constitute the most clearly defineable stationary source category in the Basin contribute a major portion of Basin stationary source NOx because of the large quantities of fuel burned. As the result of extensive compliance tests the NOx emission characteristics of large regulated boilers is well known. Characteristics of smaller unregulated boilers are less well known and tests of four units during this program helped to clarify these characteristics.

NOx emission inventories were compiled for the year July 1972 - June 1973, 1975, and 1980 based on information on unit ratings, emissions, capacity factors and fuel useage obtained from the utilities and air pollution control districts. The most pertinent results of the inventories were presented in Table D-IV listing August and December daily average NOx emissions and an annual average for each of the five Basin utility companies. The '72/'73 inventory indicated an annual average emissions of 168 tons of NO_2 per day with August and December daily averages of 68 and 128 percent of the annual average. The difference in the August and December averages is the result of high gas use (89 percent) in August and high oil use (87 percent) in December.

In 1975 the projected annual average increases by 14 percent to 192 tons of NO_2 per day as the result primarily of gas use curtailment since generation growth is near zero. This curtailment is reflected in the nearly equal August and December averages that are 106 and 109 percent, respectively of the annual average. The major impact of gas curtailment is reflected in the 78 percent increase in the 1975 August average over the '72/'73 August average. A number of units are expected to comply with more stringent regulations in 1975 and this is reflected in a decrease of 2.5 percent in the 1975 December average.

Projections for 1980 reflect nearly complete use of oil fuel and a growth in load and generating capacity equivalent to a 2.6 percent increase in Basin power generation.

The main conclusion from these inventories is that gas use curtailment during the critical summer months will increase NOx emissions to an extent that will nearly cancel out the emissions reductions achieved by the extensive utility company's effort to comply with emissions regulations. No currently cost effective control techniques are known that could be implemented to reverse this trend short of reinstituting gas fuel use. Any further reductions of power plant NOx emissions by any other known means than increasing natural gas availability is expected to result in a cost effectiveness ratio below that of the current mobil source controls, i.e., about 1.5 lb NOx reduced per dollar annual cost.

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42. Private Communication from Los Angeles City Department of Water and Power, August 20, 1973, September 19, 1973, June 24, 1974, August 16, 1974.

43. Private Communication from Southern California Edison Company, August 20, 1973, October 26, 1973, June 18, 1974, July 5, 1974, July 31, 1974, September 12, 1974.

44. Private Communication from Glendale Public Service, August 20, 1973, October 31, 1973, May 8, 1974.

45. Private Communication from Burbank Public Service, August 20, 1973, August 31, 1973, July 10, 1974.

46. Private Communication from Pasadena Department of Water and Power, August 20, 1973, October 8, 1973, June 12, 1974, June 27, 1974.

47. "Los Angeles County Power Plants Operational and Nitrogen Oxides Emission Data," Los Angeles Air Pollution Control District, Dec. 31, 1971.

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APPENDIX E

STEEL PRODUCTION

E-1   INTRODUCTION

Production of steel in the South Coast Air Basin is estimated to cause nitric oxide emissions in excess of 7000 tons per year as nitric oxide. The industry is exceeded by electrical power generation, oil refining and cement manufacture in this respect. Most of the nitrogen oxide emissions produced by this industry are produced in open hearth furnaces.

The twelve open hearth furnaces in the South Coast Air Basin produce over 4000 tons per year or an average of 340 tons per year each. These units which use a total of only 4.4×10^{12} Btu of fuel per year have an average emission factor of 1.87 lb of NOx as NO_2 per million Btu. Other than internal combustion engines only a few combustion devices of the more than 150 tested in this program, had emission factors greater than this.

Open hearth furnaces heat steel to about 3000°F before it is tapped. Since it is not a counter-current process it is necessary to discharge flue gases at temperatures above 3000°F. Since it is not economical to discharge flue gas at such high temperatures the gases from the furnace are passed through checkers. The checkers are an expanded array of refractory bricks. When the hot flue gas passes through the checkers it gives up much of its heat to the bricks. Open hearth furnaces are built with checkers at each end of them. They also have burners at each end and gates, blowers, and duct work which allows the air to pass in through the checkers at either end of the furnace and the flue gas to pass out through the checker work at the other end of the furnace. The direction of flow is changed every 5-10 minutes and each time it is changed the firing position is changed so the fuel burns in the furnace. The incoming combustion air is heated about 2500°F by the bricks which were heated during the previous cycle. This high air preheat and the resulting high flame temperature is necessary for the production of steel in open hearth furnaces.

At times oxygen is used to replace part of the combustion air. This raises the flame temperature even higher. As discussed in Section 2.1 the NO concentration is strongly dependent on the residence time, the partial pressure of oxygen, and very strongly dependent on the absolute temperature. From the relationship presented in Section 2.1 one can calculate that the NO produced is 20 times as much at a temperature of 4400°F as it is at 4000°F.

Given the excessively high flame temperatures necessary for the production of steel in an open hearth furnace and the increase in the production of oxides of nitrogen with elevated flame temperatures one would expect high emissions from open hearth furnaces.

Coke ovens in the South Coast Air Basin produce about 600 tons/year of nitrogen oxides. They burn coke oven gas which has a heating value of about 550 Btu per cubic foot and blast furnace gas which has a heating value of about 85 Btu per cubic foot. Because of its low heating value, blast furnace gas would be expected to produce a flame with a low temperature and have a low emission rate. These devices also use regenerative air preheaters. The air and fuel pass in through checkers which have been previously heated, burn, pass between ovens giving up heat to the coke and out through checkers on the other side. The direction of flow is reversed about twice every hour.

Boilers used for steam generation in order to produce steel are also a large source of oxides of nitrogen. The boilers differ from typical industrial boilers in that they burn coke oven gas and blast furnace gas as well as oil fuel. The blast furnace gas should produce low nitric oxide emissions in boilers.

Sinter machines are devices which make chunks big enough to be used as blast furnace charge, about walnut size and larger, from fines. A mixture of iron ore and coke fines is burned on a traveling grate. The heat of combustion fuses the iron ore fines into suitable size product. Sinter machines produce oxides of nitrogen. The amount produced is rather difficult to predict as are the operational parameters which may affect the emissions. The fuel for the sinter machines is primarily coke

breeze and this material would be expected to have a high concentration of fuel nitrogen in it. The fuel nitrogen is expected to be the primary source of oxides of nitrogen emitted from these devices.

Other devices used in steel production which emit oxides of nitrogen include basic oxygen furnaces, blast furnace stoves, rolling mills, soaking pits, and reheat pits. The total oxide emissions from these sources is minor relative to the emissions from open hearth furnaces, sinter machines, boilers and coke ovens.

Since there are only 12 operating open hearth furnaces in the South Coast Air Basin and these devices are large enough that it would be difficult to over look one the inventory of these devices can be assumed to be accurate. Similarly the numbers of coke ovens and the sinter machines are well known. The boilers used in steel production were thought to be well known although at the outset the existence of a few small boilers may have been missing from the inventory. Also some reheat furnaces, soak pits or rolling mills might not have been included in the preliminary inventory based on permit information.

The emission factors for the various types of devices used in steel production were not so well known. For instance, the emission factors for open hearth furnaces could have been estimated by results obtained by two different APCDs on two different open hearth furnaces. One emission factor was double the other. The San Bernardino County APCD had recently taken readings on open hearth furnaces, coke ovens, sinter machines, etc. and made an emissions inventory for steel production in that county.

Of the 12 open hearth furnaces 4 were tested. The testing of 1/3 of the devices of this type was necessary since the emission factors were not well known and the emissions from these devices were thought to be large. In addition to the fact that 1/3 of the open hearth furnaces were tested, they were each tested through a complete cycle of 8 to 12 hours and one was tested on two different days.

Of the 7 coke oven batteries, 2 were tested. Two adjacent batteries were tested in order to establish the effect of fuel type. The emissions from these devices had been reported by the San Bernardino County APCD. however, it was desirable to check the emissions from these devices since the emissions were not thoroughly documented over a complete cycle.

Emissions from both sinter machines were measured. It was necessary to measure these since the emissions from the machines were somewhat in doubt from limited data available.

Two boilers were tested. These boilers were burning blast furnace gas and coke oven gas. These tests were used to establish the emission factors for boilers burning these types of gas.

Only two rolling mills and two reheat pits were tested. There are a number of these devices but they have low heat rates and low emission factors so an error in the emissions factors for these devices will not cause a significant error in the inventory.

Sampling

Open hearth furnaces are arranged in a row so one set of transport services can be used for all of the furnaces at one site. The scrap iron is brought to the furnaces in small rail cars. The rails runs along the front side of the furnaces at the hearth level. Also on the front may be an overhead traveling crane to deliver the ladles of molten pig iron to the furnaces. The furnaces are tapped at the back and steel drains into ladles. These ladles of steel are carried away by another overhead crane which runs along the back of the furnaces. This activity of bringing iron to the furnaces and removing steel from the furnaces as well as the clustering of the furnaces made it difficult to park the instrument van close enough to the furnace for easy sampling access.

The open hearth furnaces are balanced draft devices with the furnaces being slightly positive, i.e., less than 0.1 inches of water above atmospheric. From the exit of the furnace through the checkers, the waste heat boiler and the precipitator up to the induced draft fan the pressure is below atmospheric. Any openings in the ducts or equipment causes leaks into the flue gas. In the checkers which is made of refractory brick the leakage is especially bad. In order to get samples which were as little diluted as possible by air one would want to sample at locations as close to the actual furnace as possible. This procedure would give results which might be slightly more accurate and it would allow a closer determination of the change in oxides of nitrogen emissions as a function of excess air in the furnace. The furnaces themselves may have air fuel ratios so near stoichiometric that slight changes in the air fuel ratio could be masked by air leaking into the exhaust stream if the sample was taken very far downstream.

If samples are taken at the open hearth furnace exit the flue gas temperature will at times be greater than 3000°F. A cooled probe is thus required. For the most part samples were not taken at this location although in order to determine if oxides of nitrogen were either forming or disassociating in the checkers some samples were taken at this location. Figure E-1 is a schematic of the flue gas flow from an open hearth furnace. Sample point one shows where the cooled probe was used.

Samples can be taken at the discharge of the checkers. At this point some leakage of air into flue gas has occurred but the gases have cooled to temperatures which are low enough to allow a non-cooled probe to be used. Two other difficulties with this sample point are that flue gas can be sampled from this point for only half the cycle and the gas flow can not be conveniently measured at this point. This sample point is shown as sample point 2 in Figure E-1.

Gases from open hearth furnaces can be sampled after the waste heat boiler which has the advantage that the flue gas can be monitored continuously. However, at this point the air leakage into the flue gas has been substantial. Sample point 3 on Figure E-1 shows where this sampling point is.

In order to obtain samples at a location where it is feasible to attempt measuring the gas flow rate it is necessary to take samples after the electrostatic precipitator. This sampling point is identified as sample point 4 on Figure E-1. Flue gases from open hearth furnaces have nitric oxide concentrations which are higher than the highest standard gas. Therefore in order to assure the validity of the results at these high concentrations some samples were taken for wet chemical analyses and the results of these wet chemical analyses were compared with instrument readings taken at the same time.

The gases from the sinter machines were sampled from ducts near the stack. By this time the gases had been intentionally diluted to lower their temperature so they would not overheat the materials in dust collection system (baghouse).

Oxygen Lance (for use with Molten Pig Charge)

Furnace

Burner
Fuel &
Oxygen

Hearth
Level

Lower
Level

Forced Draft
Fan

Reversing
Valve

Sample Point 1

Checkers

Sample Point 2

Electrostatic
Precipitator

Sample Point 3

Sample Point 4

Waste Heat
Boiler

Stack

Induced Draft Fan
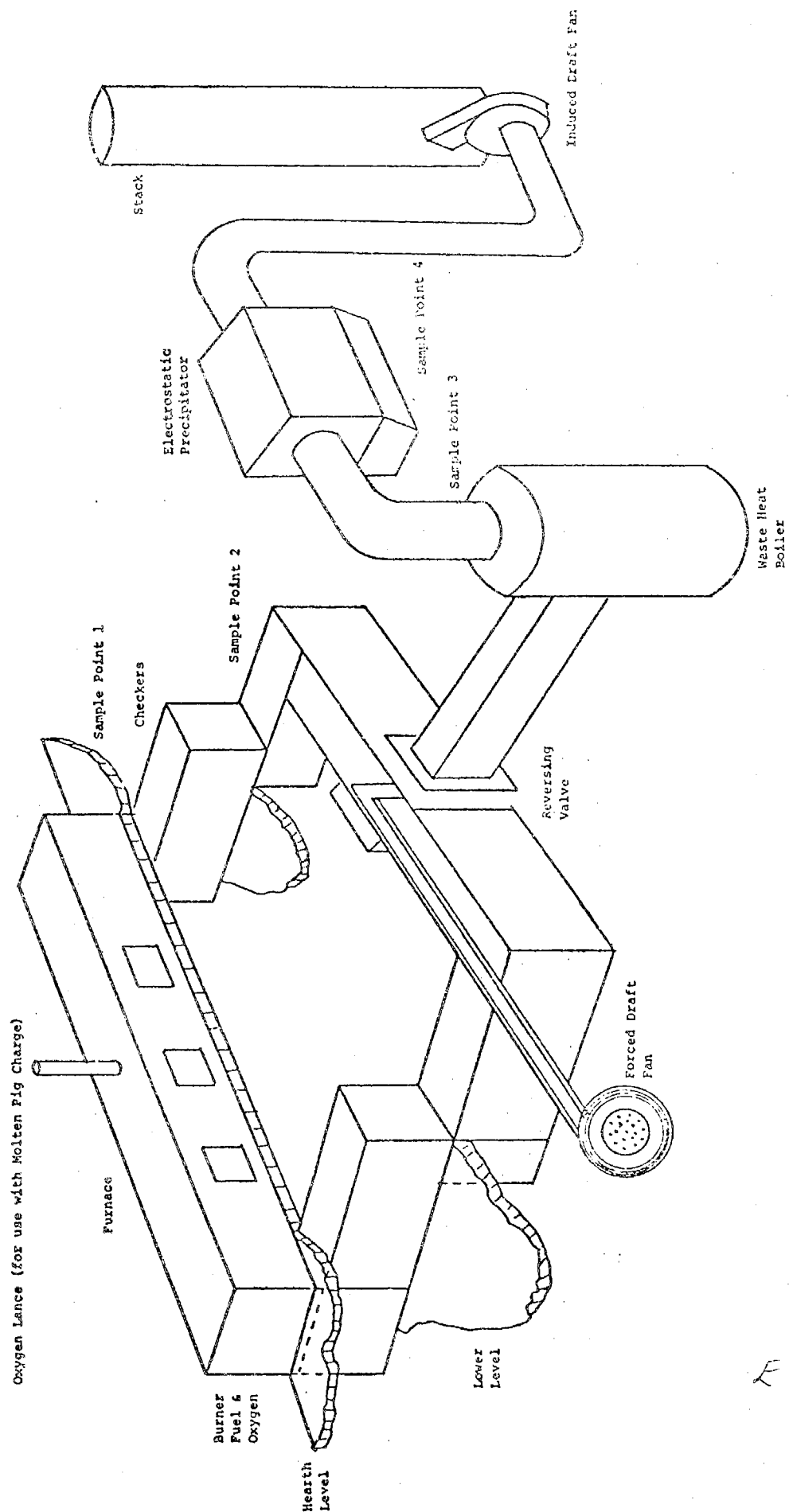
Figure E-1.   Schematic Of An Open Hearth Furnace

E-7

The gases from the soak pits were sampled at the discharge from
the pits. From this point the gases from four pits were combined in one
common stack. It was therefore necessary to sample the gases near the
actual pits.

The boilers, coke ovens and reheat furnaces were sampled from
the stack or locations near the stack entrance.

Operational Aspects of Testing

Each of the open hearth furnaces which were tested were monitored
over a complete cycle. This required 6 to 12 hours run time to test a
furnace through the steps of, repairing the furnace bottom (making bottom),
charging, melting, making steel and tapping. Random fluctuations in
oxygen concentration and the associated emissions variations were noted.
Different open hearth furnaces were sampled at various locations in order
to: obtain results which would reflect the change in oxides of nitrogen
concentration with oxygen in the furnace; make continuous measurement of
the emissions; make gas flow rate and NOx concentration measurements at
the same place; and determine if NOx was produced or decomposed in the
checkers.

The soak pits were tested while the steel was being brought to
temperature, high fire, and while the steel was being held at temperature,
low fire.

Coke ovens and boilers were tested with two different fuels.

Results

Figures E-2, E-3, E-4, and E-5 show the emissions from the four
open hearth furnaces as a function of time. Clearly the figures show
the oxides of nitrogen emissions increase as the metal temperature increases.
It can be seen from Figures E-4 and E-5 that the emissions are lower after
the hot metal is added. This lowering may be due to the hot metal addition
itself or it may be due to the fact that at the time the molten metal is
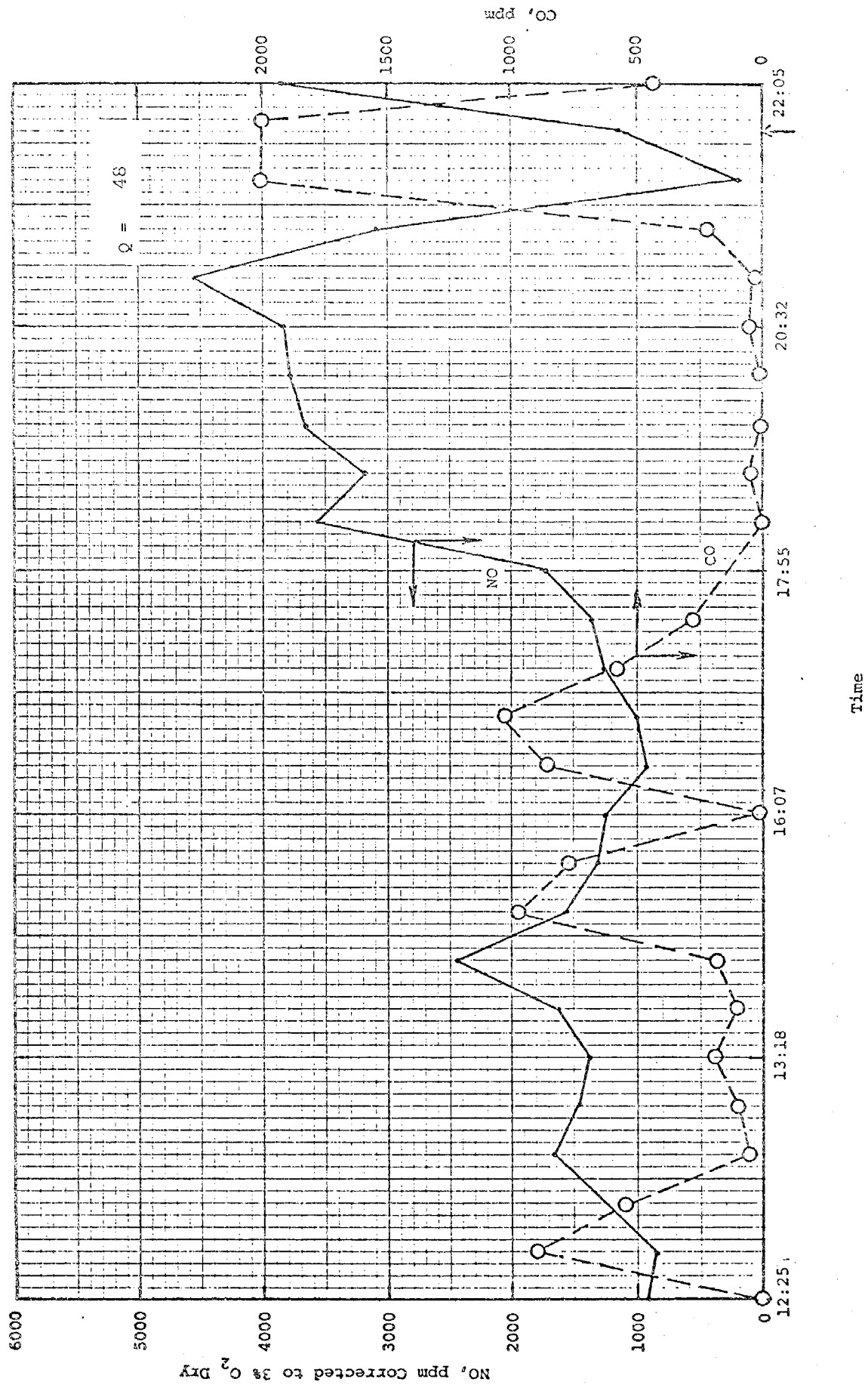
Figure E-2. Nitric Oxide Emissions and CO Level Versus Time:
#4 Open Hearth Furnace

5800-179

E-9
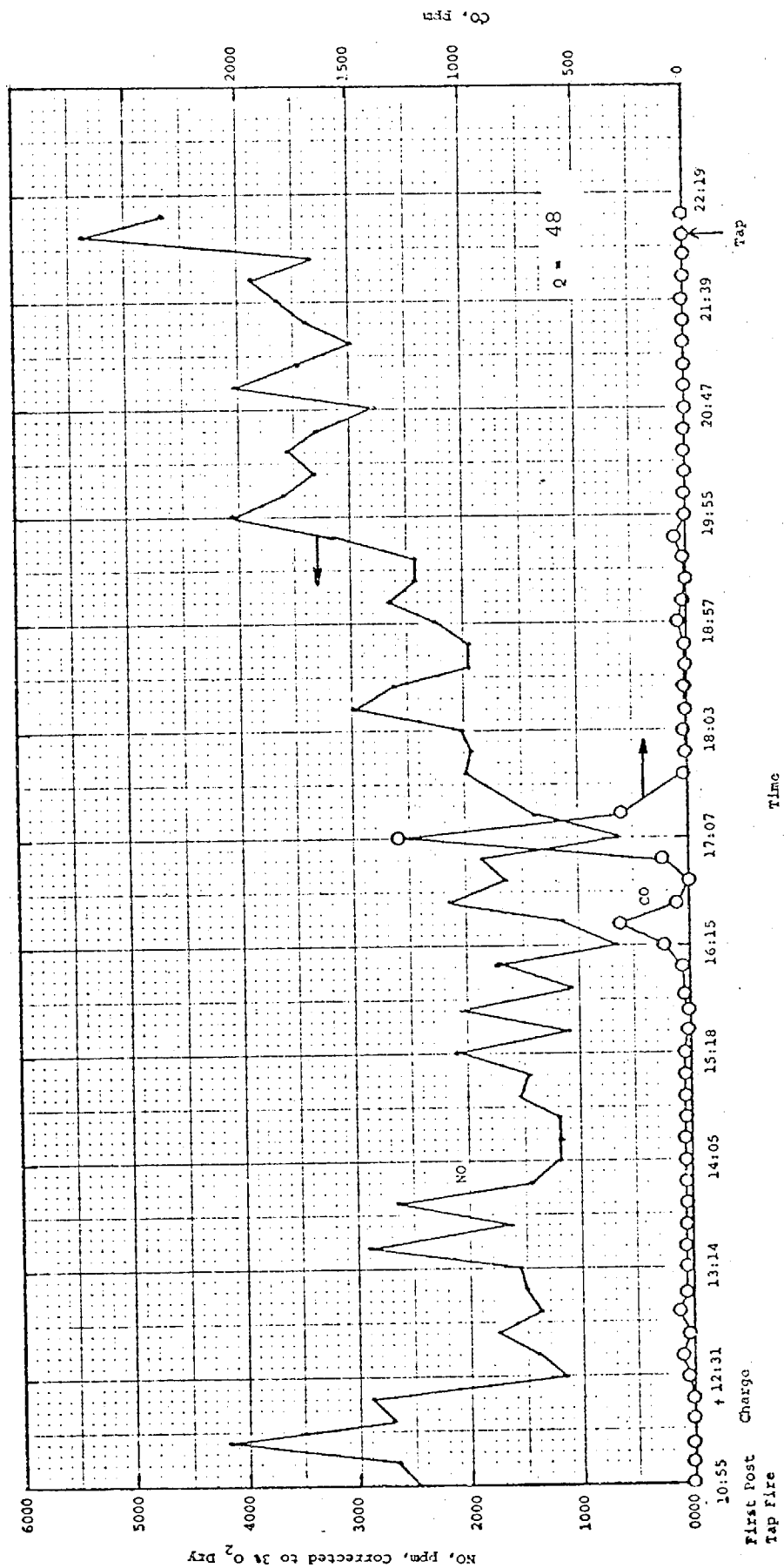
Figure E-3. Nitric Oxide Emissions and CO Level Versus Time,
#1 Open Hearth Furnace

5800-179

E-10
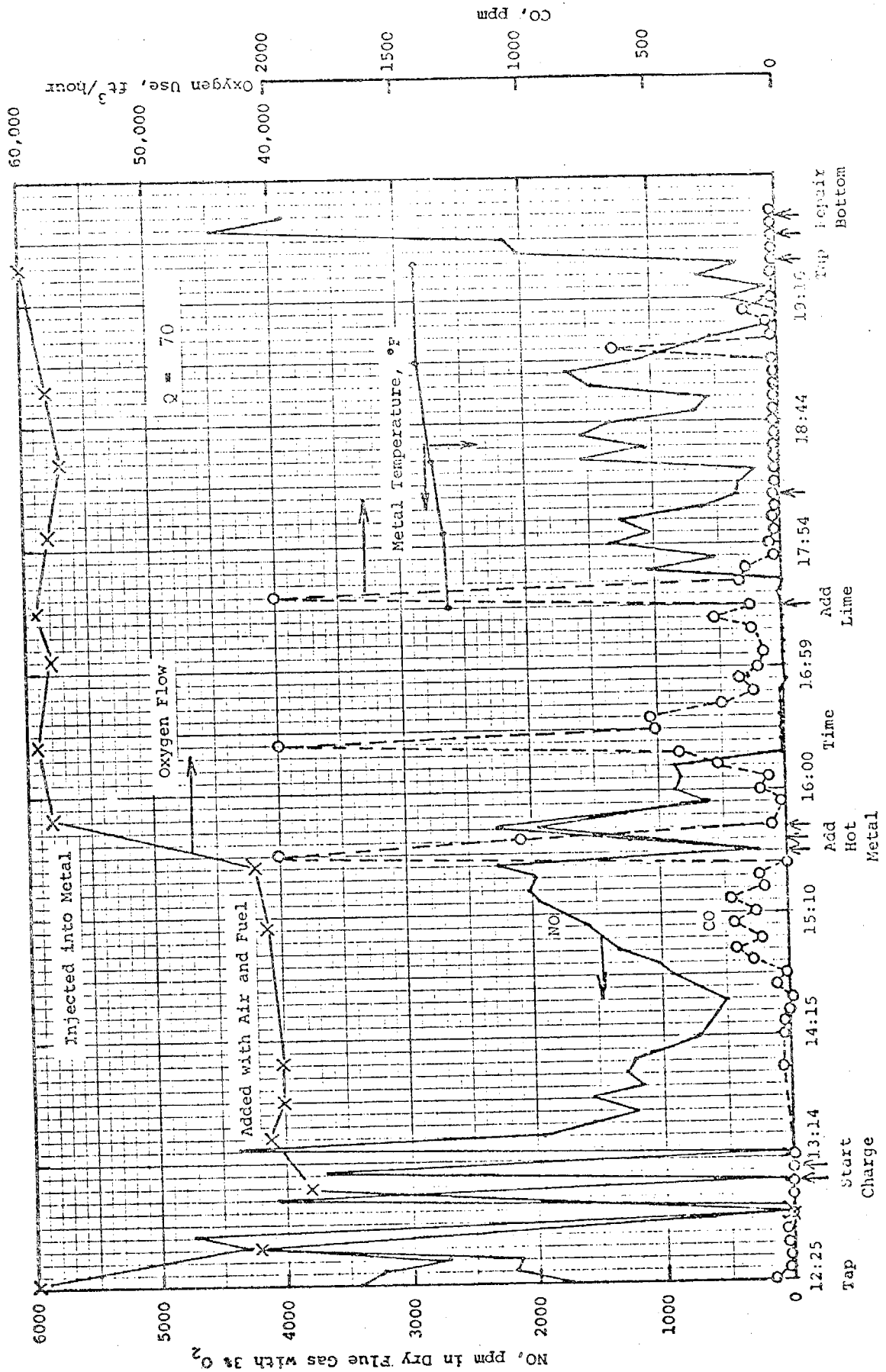
Figure E-4. Emissions #2 Open Hearth Furnace
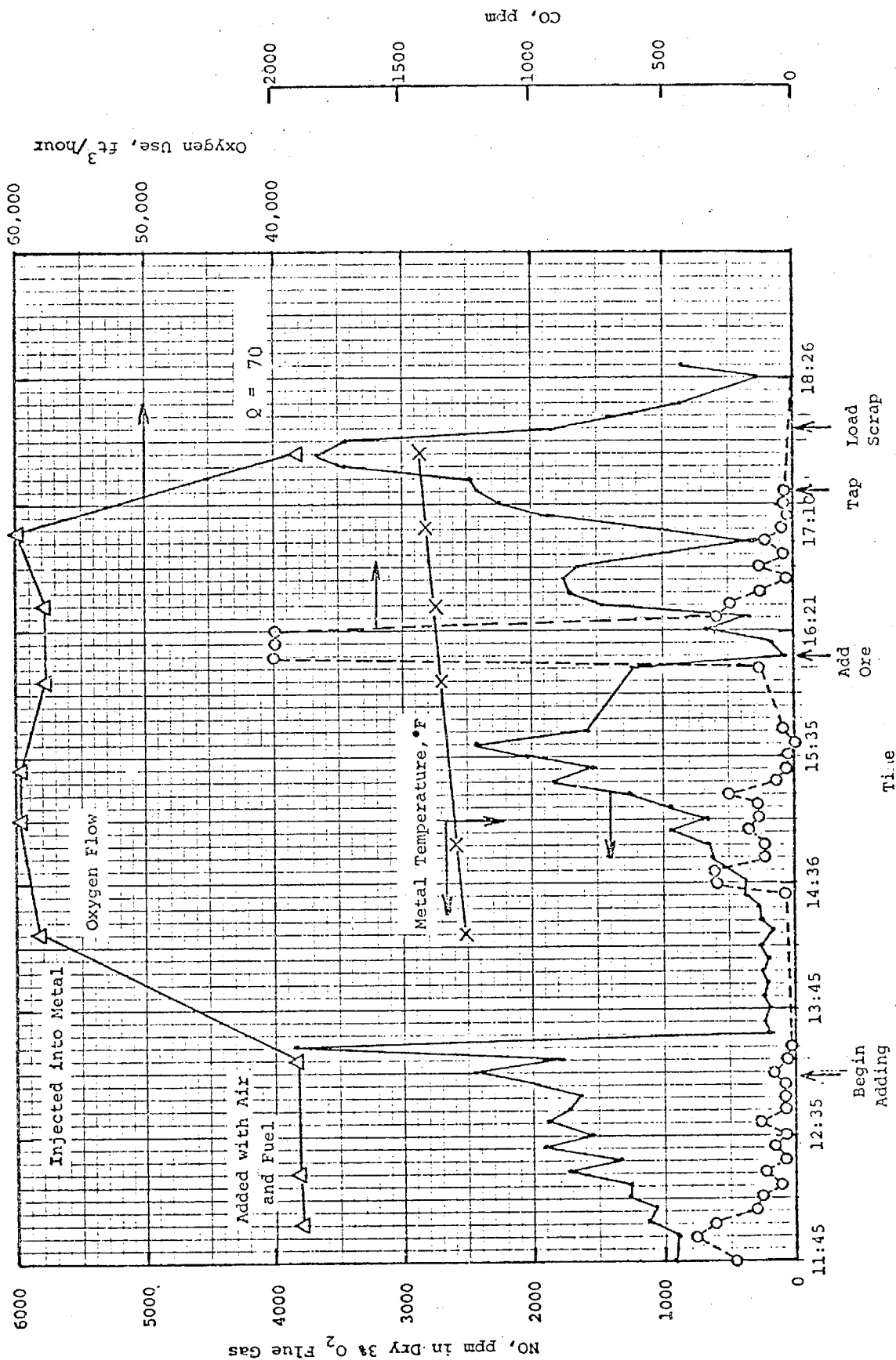
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Figure E-5. Emissions #7 Open Hearth Furnace

5800-179

added the operators begin lancing the oxygen into the metal rather than adding it with the air and fuel. It can also be seen from Figures E-2, E-3, E-4 and E-5 that in general the NO goes down where the CO goes up.

Oxides of nitrogen decrease very rapidly with flue gas oxygen concentration in open hearth furnace operation. Figures E-6 and E-7 show the oxygen-nitric oxide curves for the two furnaces from which the samples were drawn very near the furnace. Open hearth furnace number one was sampled at the discharge from the checkers. The results from this furnace, shown in Figure E-6, show the nitric oxide concentration falling to very low levels as the oxygen in the flue gas falls to 1%. The results from open hearth furnace number two, which was of a different type, are shown in Figure E-7. Here the nitric oxide falls to very low levels when the oxygen in the flue gas falls to 7.5%. Since the gas from this furnace was sampled after the waste heat boiler it was more diluted by air leaking into the flue gas which may be the sole reason for the nitric oxide dropping to very low levels at oxygen concentrations as high as 7%. Also data points representing two types of operation can be seen on Figure E-7. It is not clear if high flue gas oxygen is one of the necessary conditions of operation before hot metal addition.

The wet chemical method, phenol-disulfonic acid procedure, was used to check the instrument results. Triplicate samples were taken at four different times from an open hearth furnace. Four instrument readings were taken at the same time. In spite of large swings in the nitric oxide concentrations in a very few minutes, the average of the twelve wet chemical samples was within 2% of the average of the four instrument readings taken at the same time.

The gas samples taken near the furnace exit, with a cooled probe, showed the same corrected nitric oxide level as the samples taken after the checkers.

The time average emissions over a cycle for the two open hearth furnaces which used molten pig iron for part of the charge were calculated
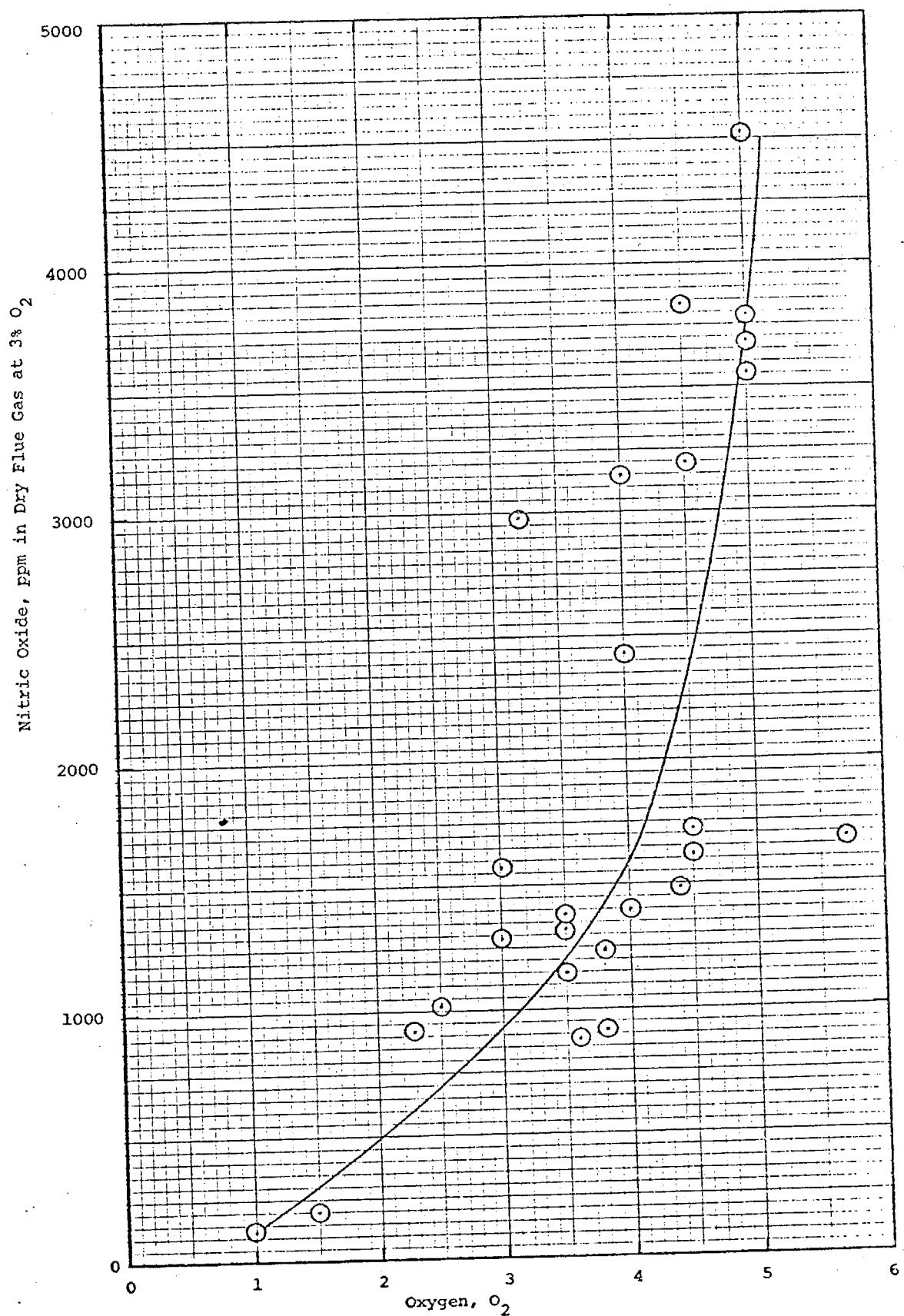
Figure E-6. Nitric Oxide Emissions Versus Oxygen;
#4 O.H. Furnace

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E-14

Figure E-7. Nitric Oxide Emissions Versus Oxygen; #2 Open Hearth
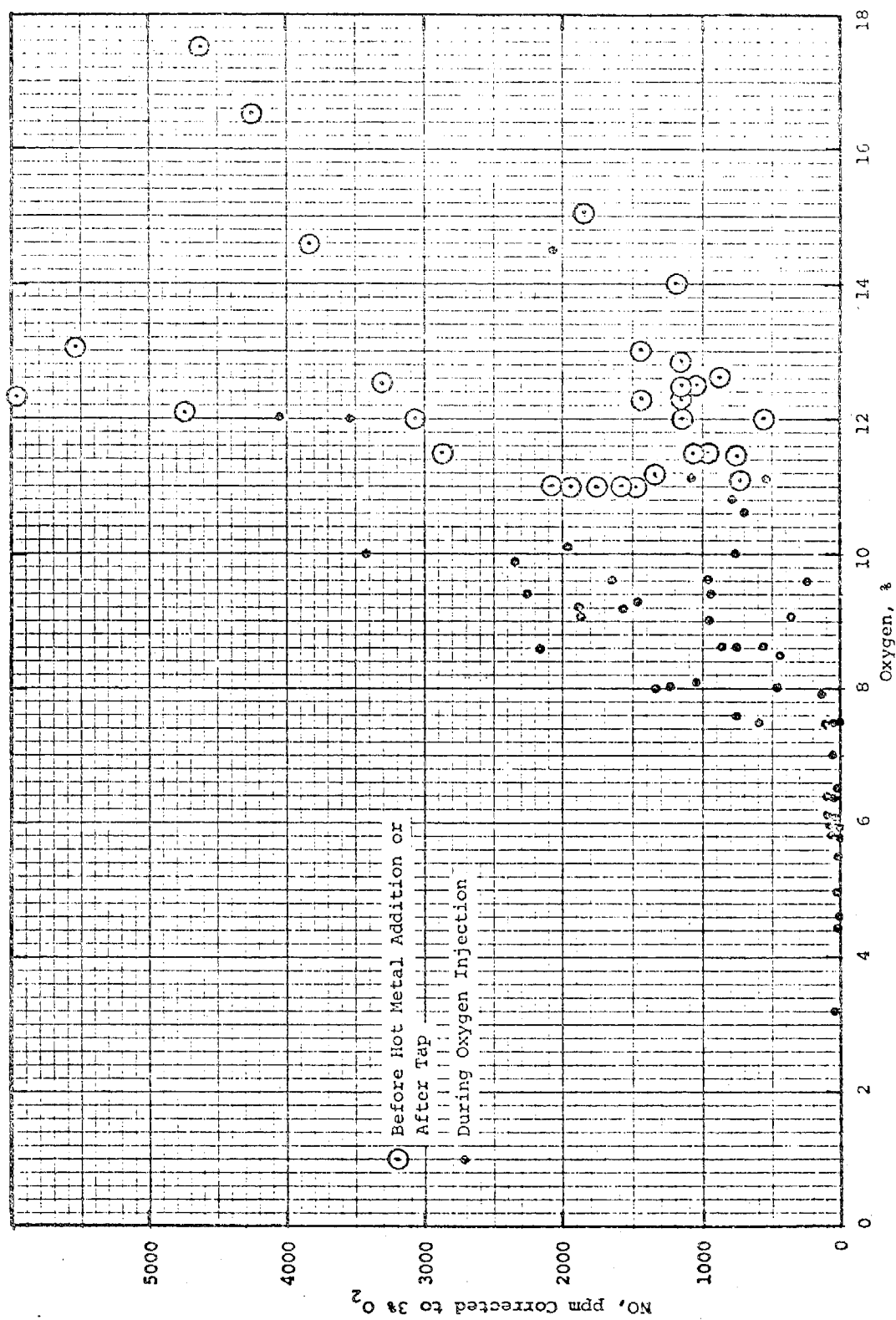
to be 1320 ppm NO and 1268 ppm NO corrected to 3% O_2 in dry flue gas. The average is 1294 ppm NO which converts to 1.58 lb of NOx as NO_2 per million Btu. This average emission factor was used for the eight operating open hearth furnaces of this type in the South Coast Air Basin.

The results of this testing, an emission factor of 1.58 lb NO as NOx per million Btu, and the fuel use information supplied by the operator of this type open hearth furnace resulted in a calculated annual emissions that was 3% less than the annual emissions found by the San Bernardino APCD for these units.[54] This agreement is very close when one considers the variations in NO concentration from unit to unit from charge to charge and especially from minute to minute, as shown in Figures E-5 and E-6.

The two open hearth furnaces which were tested that produce steel only from scrap had emission factors of 2.85 and 2.40 lb NO as NOx/million Btu. These factors were used for these furnaces and the average was used for the two other furnaces of this type.

Data from the LAC APCD[61] indicated 307 ppm NOx in the exhaust gases from the furnaces, which are cold metal furnaces. The flow rate was 17000 CFM. This would indicate an emission rate of 40 lb/hr or an emission factor of about 0.8 lb of NOx as NO_2 per million Btu if the firing rate were 50,000,000 Btu/hr which is typical of these units. Alternately an emission factor of about 0.6 lb of NOx as NO_2 per million Btu could be calculated from the average flue gas oxygen level given in the test report. In any case the emission factor established during this program for these units is 3 to 4 times as large as the previously available factor.

The two sinter machines had average emission factors of 0.4 lb of NOx as NO_2 per million Btu. These units also had CO emission levels of 1400 to over 2000 ppm (full scale on the high range of the instrument). This emission factor times the reported gas and one time measured coke use, results in an annual emission rate which is only 40% of the value reported by the SBC APCD. The discrepancy could be in one of the measurements or a difference in operating conditions.

Coke oven battery F when tested was burning mostly blast furnace gas. It had an average emission of 121 ppm NO in 3% O_2 dry flue gas. This concentration of NO converts to an emission factor of 0.21 lb/10^6 Btu when a correction for the dilution due to the inerts in the blast furnace gas is made. Coke oven battery G when tested was burning coke oven gas. The average concentration from this unit was 176 ppm NO in dry flue gas containing 3% O_2. This concentration also converted to an emission factor of 0.21 lb per million Btu. This factor was therefore used to calculate the emissions from the coke ovens.

The emissions for the coke ovens calculated from the emission factors 0.21 and the fuel use supplied by the operator was 91% of the value reported by the San Bernardino APCD.

Of the two boilers tested, one was burning blast furnace gas resulting in an average nitric oxide concentration of 62 ppm NO corrected to 3% O_2 in dry flue gas. This converted to 0.12 pounds of NOx as NO_2 per million Btu. The other boiler was burning a mixture of blast furnace gas and coke oven gas and it had an average nitric oxide concentration of 53 ppm corrected to 3% O_2 in dry flue gas. This concentration converted to an emission factor of 0.076 lb of NOx as NO_2 per million Btu. Using these emission factors and an assumed emission factor when burning number 6 oil of 0.4 lb NO_2 as NOx per million Btu resulted in an inventory which was within 4% of the value found by the APCD.

The two reheat mills which were tested were burning natural gas. One was firing at a low level and the other was firing at a normal level. They had emission factors of 0.109 and 0.138 lb of NOx as NO_2 per million Btu. The average of these emission factors, 0.123 was used for devices of this type.

Two soak pits were tested for nitric oxide emissions. An emission factor of 0.113 lb of NOx as NO_2 was established for these type devices.

Only a small number of units of any type used in the production
of steel were tested. Four open hearth furnaces were tested. However this
represents 1/3 of the total population in the South Coast Air Basin. Of
the other types of devices tested two each were tested. With such a small
number of devices tested it was only possible to establish emission factors
on the basis of type of device, gross differences in design or operation,
and type of fuel.

The emissions of NOx as NO_2 from steel production in the South
Coast Air Basin has been calculated to be 7090 tons per year. One hundred twelve
devices produce this amount. Of this amount 4246 tons or about 2/3 is
produced by the twelve open hearth furnaces. The 7090 tons per year is about
4.5% of the total emissions from stationary sources in the South Coast Air
Basin.

The results are tabulated below:

IRON & STEEL PRODUCTION
NOx EMISSION

| Device | Number of Devices | Q Range 10^6 Btu/hr | Emissions NOx as NO_2 | | |
			Summer tons/day	Winter tons/day	Annual tons
A. Open Hearth Furnaces	12	55 to 72	12.620	11.863	4246
B. Coke Oven Batteries	7	112	1.727	1.840	612
C. Sinter Machines	2	116	.700	.700	178
D. Boilers	8	28 to 314	2.146	4.277	826
E. BOF	3	0	1.050	1.050	381
F. Other*	80	7 to 420	2.629	2.837	847
Totals	112	0 to 420	20.872	22.567	7090

*Soak Pits, Reheat Furnaces, Rolling Mills, Blast Furnace Stoves, etc.

E-4   STEEL PRODUCTION EMISSION REDUCTION POTENTIAL

Open Hearth Furnace

Figures E-6 and E-7 show the emission from two open hearth furnaces as a function of oxygen in the flue gas. Considering Figure E-6 it can be seen that the nitric oxide emissions from No. 4 open hearth furnace would be below about 1500 ppm when the oxygen level as measured at the exit from the checker work is maintained below 4% . If a way could be found to maintain oxygen below this a significant NO reduction would result. It might not require new operation conditions but only that the operation be confined to a part of the current range of conditions. It would require testing, instruments and probably new controls for each furnace. For comparative cost effectiveness computation, a cost on the order of $125,000 has been estimated for each furnace since each furnace must have dual instruments and controls to accommodate fire from either end.

At 3.5% oxygen the emissions factor for No. 4 open hearth furnace is $1.5 \text{lb}/10^6$ Btu. This emission factor is 0.9 (2.4 minus 1.5) $\text{lb}/10^6$ Btu lower than the average emission factor for this furnace. If emissions from all four of the furnaces at this location, which are similar, could be reduced by this amount the emissions from this plant would be reduced by 1,072,000 lb/yr. The initial cost of $500,000 for the purpose of this assessment is assumed to be annualized at a rate of 20% or $100,000 per year. The equipment maintenance cost estimated at 5% would be $25,000/year. On the other hand, the reduced flue gas flow will result in reduced loss of heat to the stack. The reduction in oxygen concentration in the flue gas by 2% would reduce the flue gas losses for the four units by about $12,000 \times 10^6$ Btu/year. If the fuel is valued at $\$2.00/10^6$ Btu the savings would be $24,000 per year. For this assessment it is assumed that the maintenance costs would be offset by the fuel savings. The cost effectiveness ratio would then be the annualized initial costs divided into the emissions reductions or 10 lb of NOx prevented/dollar expended for control.

Figure E-7 shows the emissions from open hearth furnace No. 2 as a function of excess oxygen. Clearly the emissions are lower when the oxygen level is lower. However, the data do not necessarily show a reduction in NO emissions with a reduction in oxygen concentration except when the oxygen is lanced into the metal. Even so, it may be possible to reduce the NO emissions to nearly zero during the main part of the steel making operation by restricting the oxygen concentration to the low end of what was found to be the normal range. That is, if during the time oxygen is lanced into the metal the oxygen in the flue gas is restricted to less than 8%, when measured just after the waste heat boiler, the NO concentrations should approach nearly zero during this time. This would result in an emissions reduction of about 35%. Further reductions might be possible by reducing the oxygen concentration during the charging and melting time. The 35% reduction would result in an emission reduction of 880 tons or 1,760,000 pounds/year. It is estimated that the 8 open hearth furnaces at this location could be equipped with instrumentation and controls which would allow the flue gas oxygen level to be closely controlled and properly set up for a total cost which is estimated for the purposes of cost effectiveness comparison to be about $1,000,000. If annualized at a rate of 20% or $200,000/year, the effectiveness ratio would be 8.8 lb of NOx as NO_2 eliminated per dollar annual cost, assuming an even tradeoff between maintenance cost and fuel savings as in the previous example.

Figures E-4 and E-5 show the nitric oxide emissions from two open hearth furnaces as a function of time. It can be seen from these figures that the nitric oxide concentrations drop when the hot metal is added and the oxygen is introduced under the metal. This information provides clues as to how the emissions might be reduced further. For instance, it might be possible to add the hot metal at an earlier time and thereby reduce the emissions. It might be possible to reduce the oxygen used before the hot metal is added and thereby reduce the nitric oxide emissions.

Sinter Machines

Reduction of the nitric oxide emissions from the sinter machines is not seen as particularly easy or pressing, since the annual emissions from these machines is less than 90 tons each.

Boilers

These boilers have low emissions factors for the fuels which were being used when they were tested. Also, the use of the remaining fuel, oil, is very limited, so the reduction of nitric oxide emissions from these boilers does not seem to be warranted at this time.

Coke Ovens

The emissions from these devices are low and the emission factors are low. No ready approach to economic reduction of these emissions was evident from the test results.

Rolling Mills, Soak Pits, etc.

Emission reductions from these devices are not seen as practical at this time.

Conclusions

The emissions of oxides of nitrogen by steel making operations are about 4.5% of the total emissions in the South Coast Air Basin. About of the emissions by steel production are caused by open hearth furnaces.

Although not demonstrated, it is estimated that by careful control of excess oxygen the NOx emissions from open hearth furnaces might be reducible by 35%. This would be 1486 tons per year, about 1% of the total emissions from stationary sources in the South Coast Air Basin and about 20% of the emissions from steel production. The cost effectiveness ratio would be about 9 pounds NOx per annualized dollar expended for control.

Future emissions from steel producing equipment will be increased by: increasing production; additional equipment; switch to higher fraction of oil; and decreased by decreasing production and retirement of equipment, especially open hearth furnaces. Open hearth furnaces are no longer the most competitive method of producing steel so no new units are expected to be constructed, and some of the existing furnaces could conceivably be retired by 1980.

At this time there is no firm basis for projecting increased or decreased emissions for iron and steel production in 1975 or 1980.

References

54. "Final Report on an Emission Inventory at Kaiser Steel," California Air Resources Board Report 73-20-5, September 18, 1973.

61. "Emission of Air Contaminants to the Atmosphere and the Collection Efficiency of an Electrical Precipitator Controlling the Emissions from a 65 Ton Capacity Open Hearth Steel Melting Furnace," LAC APCD Report C-1476, R.M. Burlin, W.H. Parmelee, April 1971.

APPENDIX F

CEMENT PRODUCTION KILNS

F-1   INTRODUCTION

Portland cement is made by sintering a mixture of raw materials,
one of which is composed mainly of calcium carbonate (as limestone) and
the other of aluminum silicates (as clay or shale). During the sintering
process chemical reactions take place which produce clinkers of calcium
silicates and aluminates. The feed which is a mixture of the above materials
is fed into a rotary kiln which is about 500 feet long and 12-16 feet
diameter. The kiln turns slowly causing the charge to roll, tumble and
gradually move to the discharge (lower) end of the kiln. At the lower end
of the kiln it is fired with a gas or oil flame. The combustion air is
preheated to 1000°F or higher by direct contact with clinker which has
discharged from the kiln. The hot combustion gas and clinker pass counter
currently to one another in the kiln resulting in low temperature differences
and slow heat transfer. In other words, the combustion gases in a cement
kiln are cooled in 500 feet of travel about the same amount that combustion
gases are cooled in 50 feet of travel in a boiler. Even the pass through
the first 10% of the kiln where probably all of the nitric oxide is formed
may take 2 seconds which is much longer that gases are in the hottest part
of a boiler.

In a cement kiln it is critical that certain chemical and physical
changes take place. Some of these changes are exothermic. Thus, once the
charge is heated to certain temperature it may heat up several hundred
degrees more by itself.

The final clinker temperature is 2600-2900°F. The flame temperature
is necessarily higher, but, the heat transfer to this hot material is slow.

The air preheat is higher than in most industrial combustion devices.
The medium to be heated is hot which results in slow transfer of heat from
the flame to the medium and thus a nearly adiabatic flame. The very high
flame temperature and very long residence times can be expected to result
in high emissions of nitric oxide.

Figures F-1 and F-2 are schematics of kilns showing the important features and the sampling points. Air is taken in through the forced draft fan and used to cool the clinker after it discharges from the kiln. In the clinker cooling process the air is heated to over 1000°F. Some of the air is extracted, the dust is removed from it and it is discharged. Most of the air passes into the kiln where it is used to burn the fuel. The hot gases are in intimate contact with the charge material as each passes the other on their ways to their respective discharge ends of the kiln. The charge enters near ambient temperature and discharges at 2600-2900°F. The gases may reach temperatures up to about 4000°F in the flame and discharge at about 1200°F. The actual maximum flame temperatures are not readily measurable, but have been estimated by kiln designers and operators to fall somewhere in the range of 3200°F and 4000°F. After exiting the kiln the gases are cooled, either by air dilution as shown in Figure F-1 or by water spray as shown in Figure F-2, and then pass to a baghouse for dust collection. Following the baghouse the flue gases are discharged, perhaps up a stack.

There are four large kilns in the South Coast Air Basin producing typical Portland cement. Two much smaller kilns produce specialty cement products. The cement manufacturers also use dryers to dry raw materials, but these have low heat rates and low emissions.

An extremely large error (on the low side) was estimated for the major cement kilns in the preliminary inventory. This was the result of using an EPA[12] emission factor which when checked against a SBC APCD test result yielded values as much as a factor of three two low. Large temporal variations of the actual emission rate with system operating conditions were believed to occur as a consequence of the balance of conditions that set the maximum temperature in the kilns. In the preliminary inventory the daily emissions from cement kilns was estimated at 6 tons per day but an uncertainty of +300% or 18 tons per day was also estimated. An error of this magnitude was too large to be acceptable for inventory, hence a high priority was assigned to testing those major kilns.
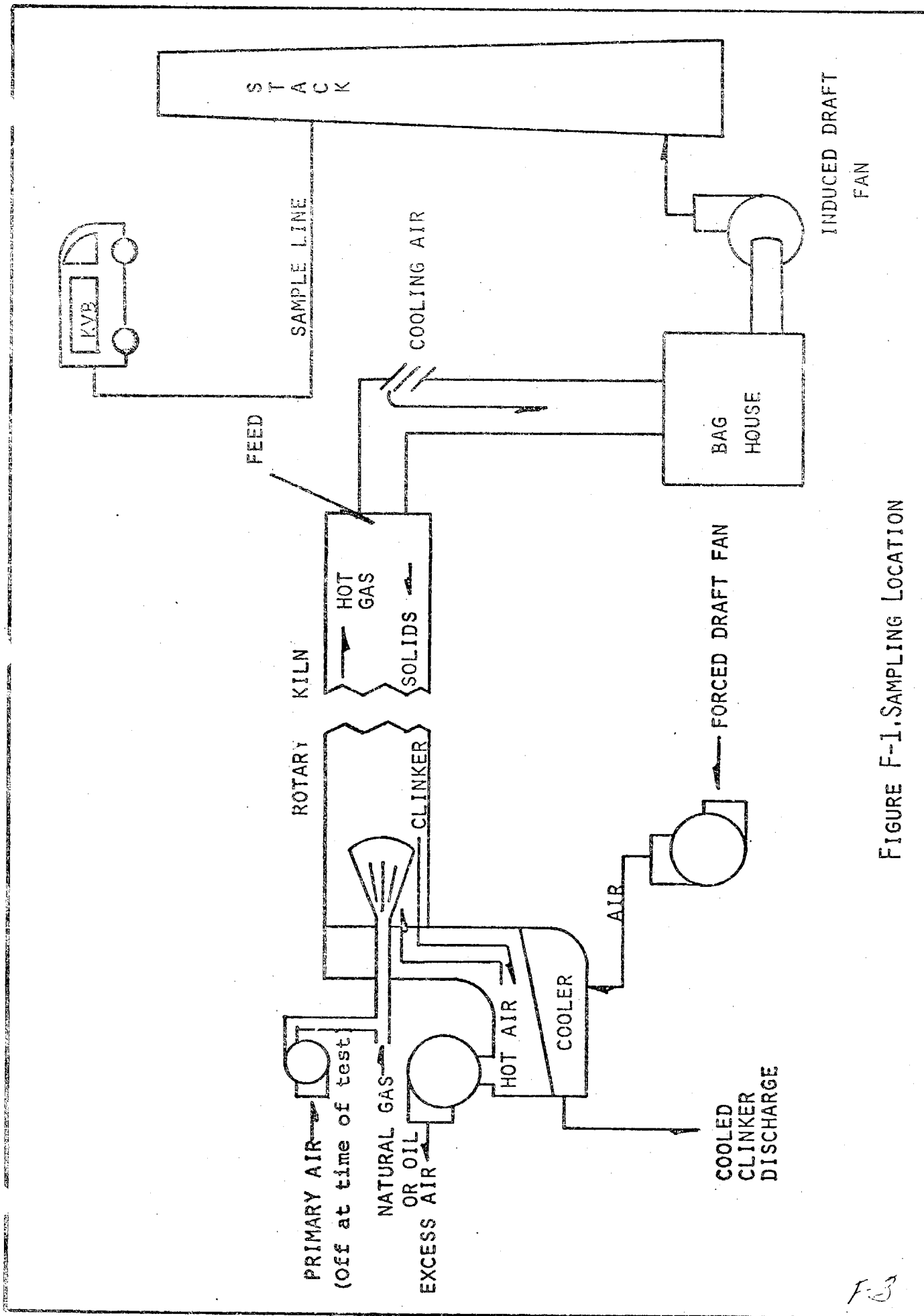
FIGURE F-1, SAMPLING LOCATION

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F-3
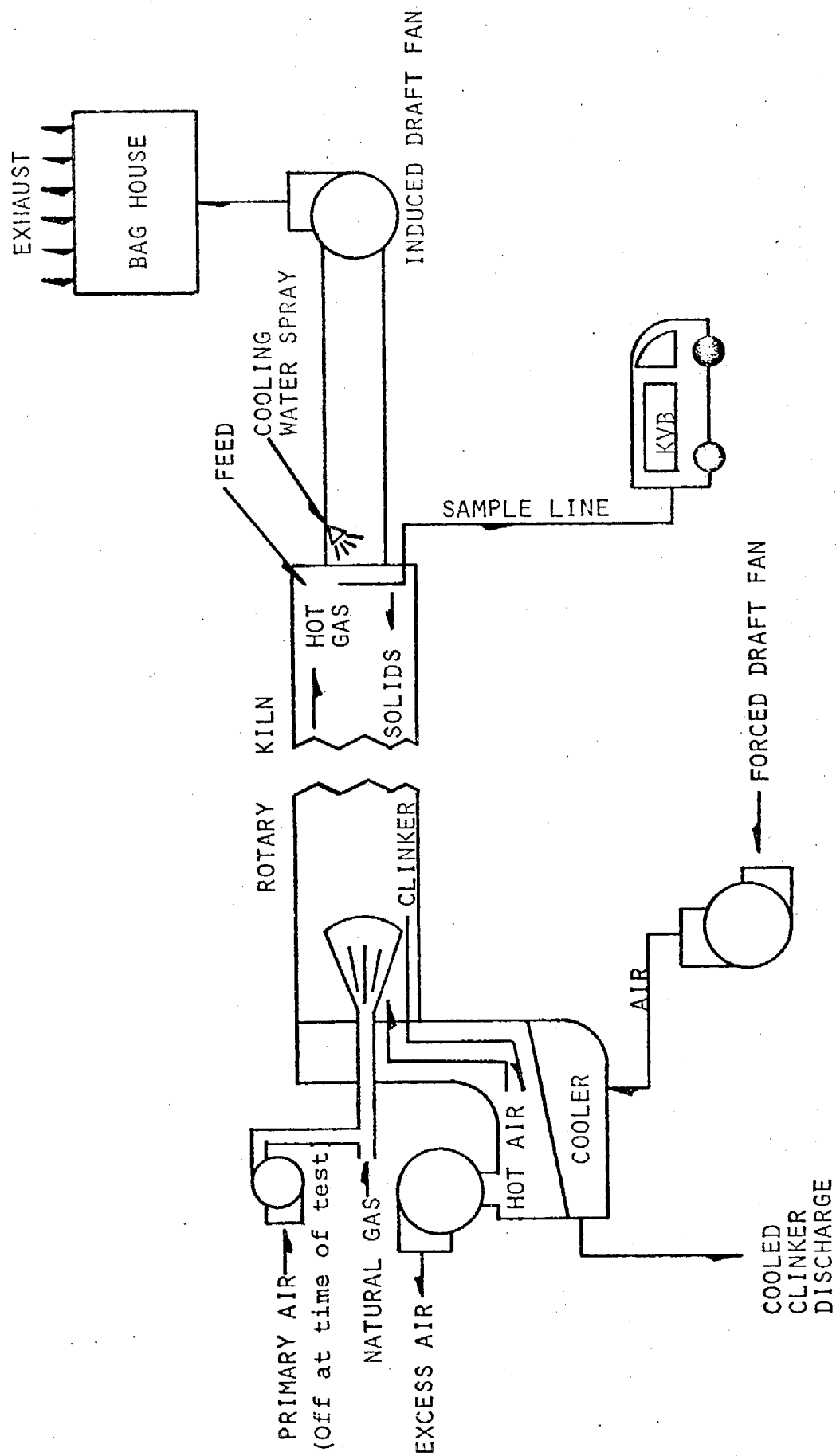
Figure F-2. Sampling Location

Of the four large kilns three were tested. The fourth was down for repairs during the program and was not available for testing. All three of the kilns tested were tested while firing natural gas. Only one of the kilns fired oil during the time the test equipment was at the cement plant. This kiln was tested when firing oil as well as gas.

F-2   MEASUREMENT OF NOx EMISSIONS FROM CEMENT PRODUCTION KILNS

Cement kilns are constructed with a steel shell and little or no air leaks into them. However, after the gas exits the kiln it may be diluted with air in order to lower the gas temperature. The gas exiting a cement kiln is usually at about 1200°F and it must be cooled enough that the gas can be handled in a baghouse. In kilns A and B air is added to the hot gases as shown in Figure F-1 and cooled to about 350°F. The gas samples from these two kilns were drawn from the stacks as shown in Figure F-1.

In kilns C and D the gas cooling was accomplished by water spray as shown in Figure F-2. These kilns had no stack. The sample was taken directly from the kiln through the operator's existing sample line. This sampling procedure allowed a careful correlation between flue gas O_2 and oxides of nitrogen.

Kiln B was tested on gas alone. Kiln A was tested both when firing natural gas and when firing oil fuel.

Kiln C was tested on gas fuel only but it was tested both at full load, normal operation and while it was being brought up to full load. Kiln C, which was sampled as shown in Figure F-2 showed a low level of flue gas oxygen but quite a bit of random fluctuations in that concentration. These fluctuations allowed a determination of the sensitivity of NOx to flue gas oxygen concentration.

Kiln A which was tested both while firing natural gas and oil
fuel showed distinct different emission levels for the two fuels. Clearly,
in this kiln, the use of oil fuel produces less oxides of nitrogen than
the use of gas fuel. In most combustion devices oil combustion produces
more nitric oxide than does gas combustion. Emission regulations usually
reflect this. Nitric oxide emission regulations are usually set 100 ppm
lower for gas fires than for oil fires. In small combustion devices with
extremely non-adiabatic flames oil flames usually produce more nitric oxide
than gas flames. However, considering that uncontrolled devices as they
become larger   have more nearly adiabatic flames, the nitric oxide
production from gas flames exceeds the production from oil flames.
As attempts to reduce the emissions from these units are made the emissions
from gas fuel flames are much more responsive to modifications which consist
frequently   reduction in the adiabatic flame temperature. Since nitric
oxide emissions from oil flames do not respond to increasing or decreasing
flame temperatures as much as the emissions from gas flames, it is not
surprising that, in the case where the combustion air is heated to a very
high temperature and the flame zone is nearly adiabatic, emissions from
oil fires are lower than the emissions from gas fires. Perhaps the most
palatable explanation for this is that a significant amount of the nitric
oxide produced in oil flames comes from nitrogen in the fuel and is only
slightly affected by flame temperature. On the other hand the thermal
formation of nitric oxide, which is the only mechanism in natural gas flames,
increases very rapidly when flame temperatures are increased as discussed in
Section 2.1.

Kiln A exhibited fluctuations in emissions while firing both gas
and oil for no readily apparent reason.   Perhaps
fluctuations in the oxygen concentration in the flame zone which were
obscured by the air dilution of the flue gas are responsible for these
emission variations.

Figure F-3 shows the corrected NO readings taken while Unit C was
coming up to full load. The NO readings are shown as a function of time.
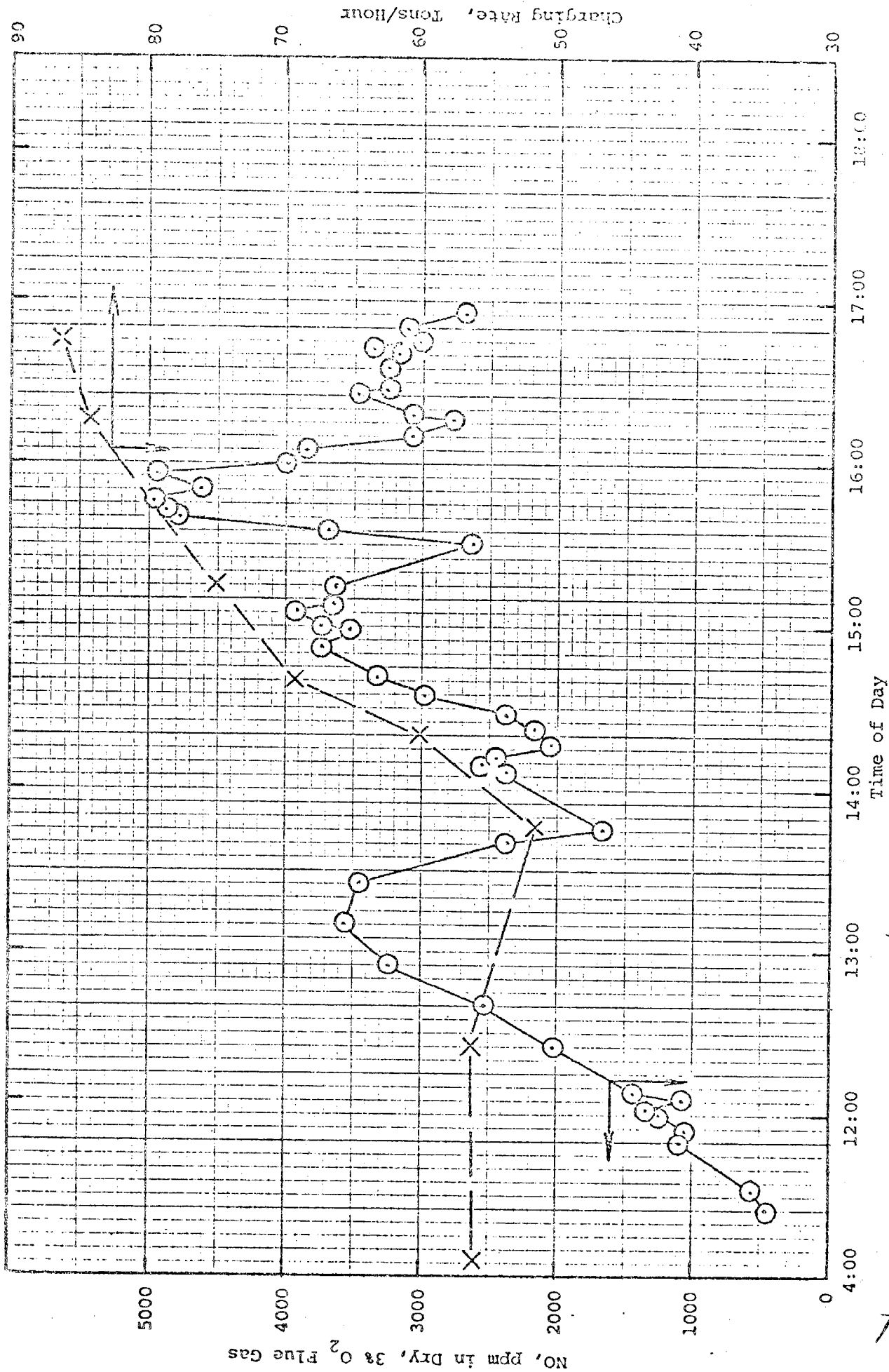
Figure F-3. NO Emissions, Cement Kiln C, April 25, 1974, Increasing Load

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F-7

On the same figure the feed rate is shown as a function of time. For the most part the emissions went up as the feed rate went up. There was a low NO reading at 1345 hrs., however. While it may have coincided with a low feed rate, it also coincided with a low oxygen reading (0.03%) and a high carbon monoxide reading (600 ppm). The peak NO concentrations which occurred at 1540 hrs. to 1556 hrs. corresponded to peak oxygen levels of 3.0 to 3.6% in the kiln. The emissions at full load for Unit C are plotted against time in Figure F-4. In Figure F-5 the emissions at full load are plotted against oxygen concentration and the reason for the variation can clearly be seen.

When firing natural gas, kilns A and B, which are supposedly identical, had emission ranges of 1680-2890 and 2790-3565 ppm NO in dry flue gas with 3% O_2, respectively. Kiln A had an emission range of 600-1085 ppm NO in dry flue gas containing 3% O_2 when firing oil.

Kiln C had emissions of 2400-5200 ppm NO(in dry flue gas containing 3% O_2)at full load. The variations were due to oxygen concentration as can be seen in Figure F-5. Kiln C had emissions while coming up to load of 500-5000 ppm NO(in dry flue gas containing 3% O_2.) These emissions can be seen from Figure F-3 to increase with load and with flue gas oxygen concentration.

The results are tabulated in Table F-I.

TABLE F-I

RESULTS OF MEASUREMENTS OF NOx

EMISSIONS FROM CEMENT KILNS

Device	Gas Fuel Flow, 1000's of CFH	Oil Fuel Flow, gpm	Feed Rate T/hr	Operating Condition	O_2,%[*]	CO, ppm	NO,ppm Measured	NO[+] Corrected
A	--	23-25	75	Steady	14-15	0	130-265	600-1085
A	230	--	75	Steady	14	0	430-490	1680-2890
B	224	--	75	Steady	14-14.5	0	620-900	2790-3565
C	100-245	--	56-96	Increasing Load	.03-10	0-600	230-3800	500-5000
C	228-260	--	95-102	Steady	1.5-5.0	0	1900-3800	2400-5200

[+] Corrected to equivalent value in the dry products of combustion containing sufficient excess air to have 3% oxygen.

[*] Oxygen levels in kilns A and B are higher because the samples were taken from the stack after the gas had been cooled by dilution with excess air. Actual levels in kiln are indicated to be near 1% O_2 by plant instrumentation.
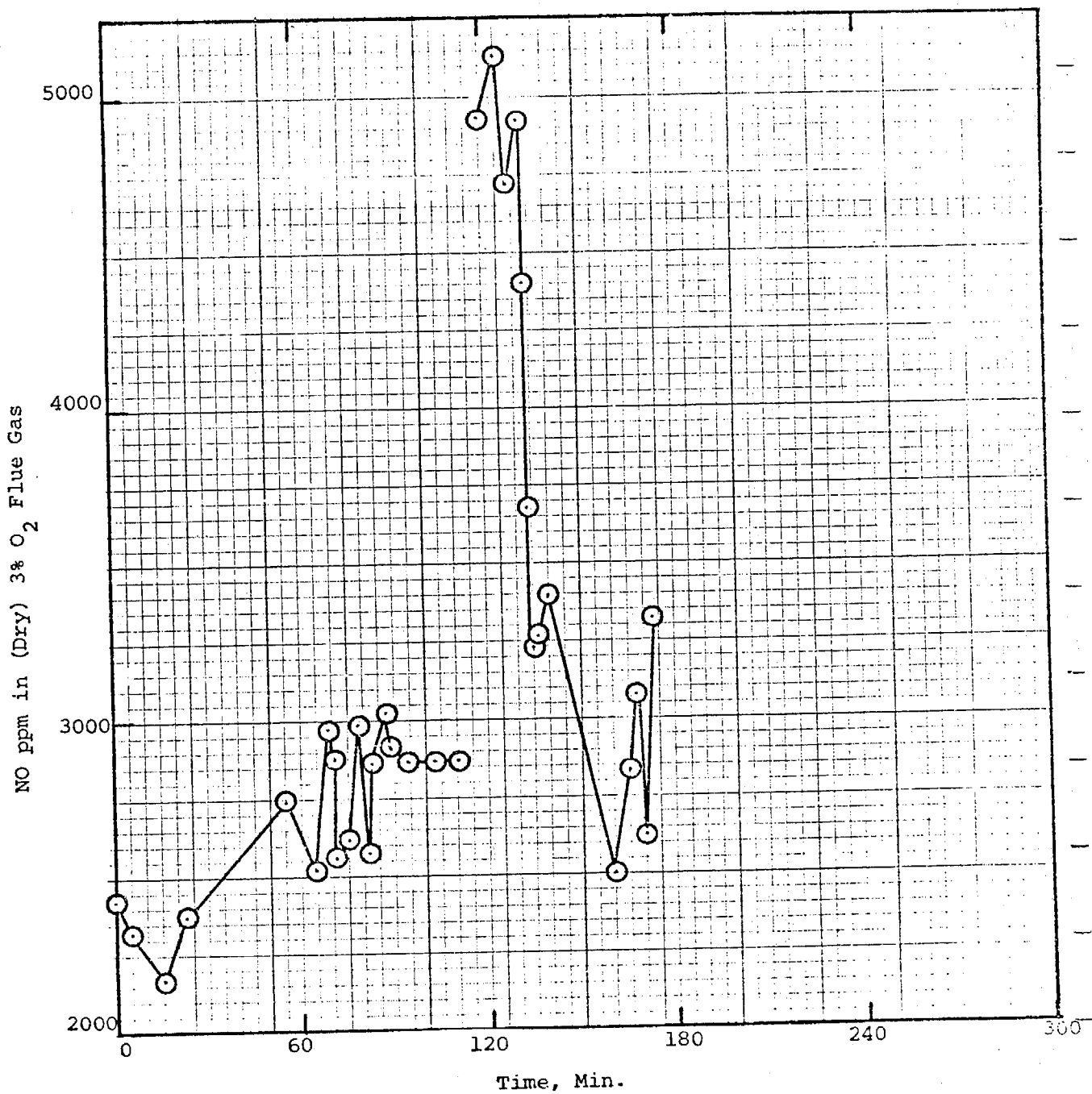
Figure F-4. Kiln C, Emissions Vs Time at Full Load, Gas Fuel

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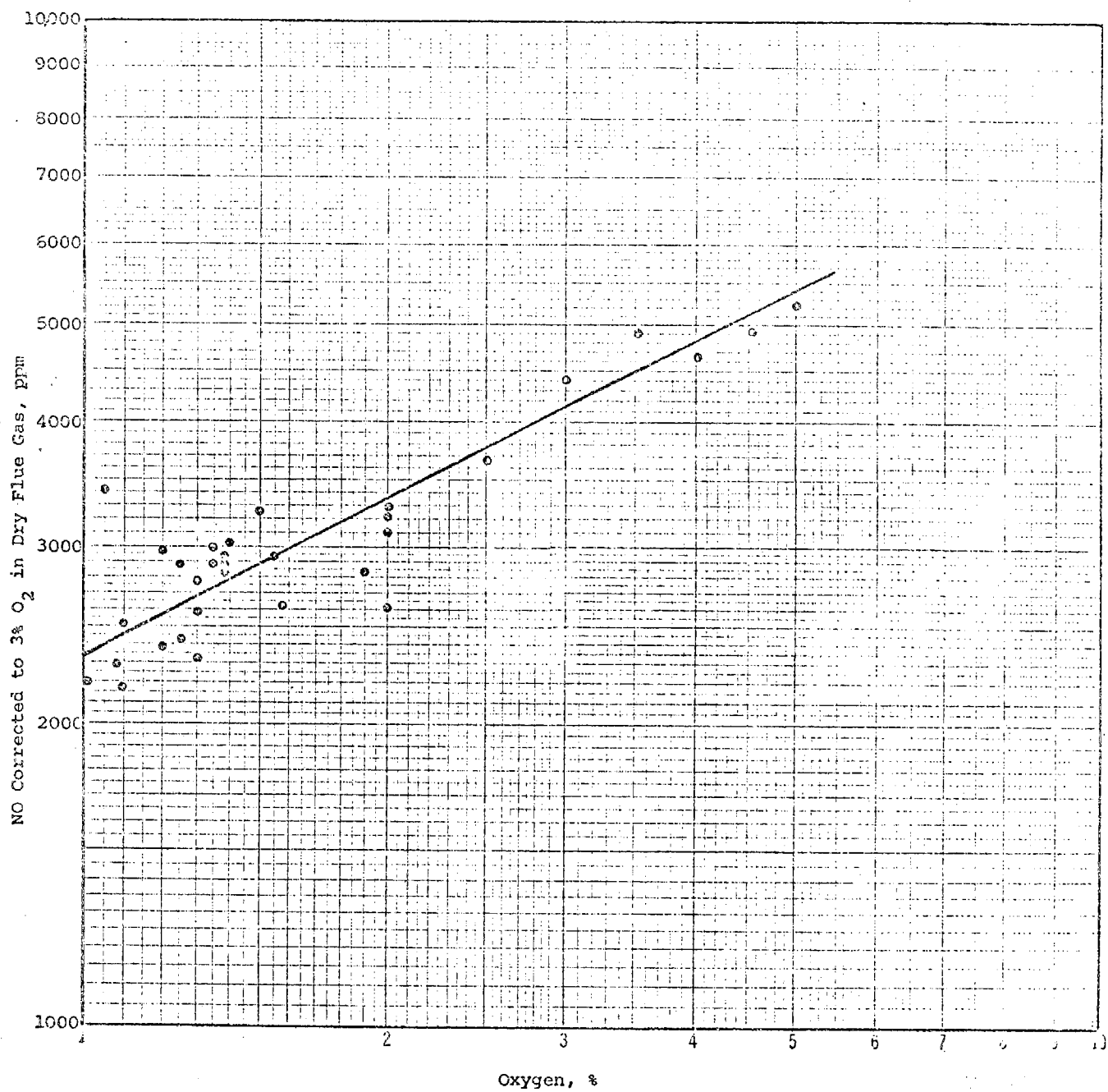
Figure F-5. Corrected NO verses O_2 in Cement Kiln C at About 100 T/hr Feed

F-11

Data Correlation

The gas fired emission factor for each of the kilns tested was determined from the time average of the measured emissions over several hours at full load for that particular unit. Unit D which is nearly identical to Unit C was assumed to have the same gas fuel emission factor as kiln C.

The average emission factor established for kiln A while firing oil was used for both kilns A and B. Kilns C and D were assumed to have oil emission factors which were the same fraction of the gas emission factors as the ratio of the factors found for kiln A.

Two small, speciality cement, kilns E and F, were assumed to have the same emission factors as the two large kilns at the same location. These kilns have low firing rates and thus low emissions.

Table F-II shows the emission factors for the cement kilns.

TABLE F-II

CEMENT KILN EMISSIONS FACTORS

Kiln	Q, MMBtu/hr	Emission factors, pounds of NOx as NO_2 per MMB	
		Gas Fuel	Oil Fuel
A	220	2.32*	1.08*
B	220	3.67*	1.08
C	350	4.2*	2.0
D	350	4.2	2.0
E	75	4.2	2.0
F	75	4.2	2.0

*Tested during this program

F-3   CEMENT PRODUCTION KILN NOx EMISSION INVENTORY

The emissions from cement kilns were found to be 11,848 tons per year or 8% of the emissions from stationary sources in the South Coast Air Basin. These kilns burn 0.5% of the oil and 1.2% of the natural gas used by commercial and industrial stationary sources in the South Coast Air Basin. The four large kilns currently operate at over 90% of capacity. At times they are in repair and it is not likely this will change in the near future.

On a summer day when burning gas the emissions from cement manufacturing is 37.4 tons per day or about 10% of the total from stationary sources in the South Coast Air Basin. On a winter day burning oil the emissions from cement production is only 13.1 tons per day or only 2.5% of the total stationary emissions in the South Coast Air Basin. The increased percentage on a summer day is due to the fact that when all units are burning natural gas most devices have low emissions relative to the emissions when burning oil, while the converse is true for cement kilns. Also for the inventory year these kilns operated at lower loads in winter.

Presented in Table F-III is a tabulation of the emissions data from cement production activities.

TABLE F-III

NOx EMISSIONS FROM CEMENT PRODUCTION KILNS IN THE SOUTH COAST AIR BASIN

July 1972 – June 1973

Device	Q, Rated Capacity 10^6 Btu's/hr	Summer Emissions tons/day	Winter Emissions tons/day	Annual daily average tons/day	tons/year
KILN	350	9.17	3.28	8.31	3033
KILN	350	9.17	3.28	8.31	3033
KILN	220	9.69	2.74	7.52	2746
KILN	220	6.13	2.74	4.90	1788
KILN	75	1.59	0.47	1.69	616
KILN	75	1.59	0.47	1.69	616
DRYER	65	0.00	0.01	0.00	0
DRYER	30	0.03	0.03	0.02	9
DRYER	27	0.02	0.01	0.02	6
DRYER	16	0.01	0.01	0.01	3
BOILER	12	0.00	0.02	0.01	3
Total	1440	37.4	13.0	32.5	11848

It is assumed that due to decreasing natural gas availability these operations will be burning about 100% oil in 1975 and beyond. It is estimated that the emissions would be reduced by about 5400 tons per year as a direct result.

F-4   CEMENT PRODUCTION KILN EMISSION REDUCTION POTENTIAL

The two cement plants in the Basin emit about 12,000 tons per year of NOx. Of this amount 10,600 tons are emitted by only four devices. Each device has only one burner. Therefore, in terms of numbers of devices and numbers of burners cement kilns are high emitters. Thus an effort on combustion modification or stack gas treatment could, if successful, result in a large reduction in the NOx emissions.

Modified Operation - Reduced Excess Oxygen

Kilns A and B when firing gas had very different emission factors from each other. It should be possible to find the difference, which may oxygen level in the kiln or burner design or operation, and operate both kilns to emit as kiln A does. Finding the difference might not be simple since the kilns are thought to be nearly identical. Since the range of emissions from the two kilns barely overlap it would seem the kilns could be operated to produce NOx at the lower level. Similar changes might reduce the emissions from kilns C and D.

In addition to the differences between kilns there is a wide variation with time in the emissions for each kiln. Most likely changes in the oxygen concentration in the flame is the most important independent variable. While NO formation is a very strong function of temperature it is also directly related to the square root of the oxygen concentration. Therefore reduction in oxygen concentration should reduce the nitric oxide emissions. Figure F-5 shows the effect of excess oxygen on the nitric oxide emissions from kiln C. If the units could be operated full time at the low end of the range which was presented as typical, the emissions could be reduced significantly. For instance, at 1.2% oxygen in kiln C the NO concentration would be 2600 ppm, the emission factor would be 3.2 lb per million Btu and the emissions from kiln C and D would be reduced by 624 tons/year or about 20%. It would not be necessary to produce clinker under new conditions. This reduction could be achieved by confining the operation to part of the normal range. In order to optimize the reduction it would be necessary to characterize the desired

operating condition with more detailed testing and to install some new instruments and perhaps even controls.

Kilns A and B were sampled in the stack and therefore the dilution of the flue gas with air obscured the changes in emissions with oxygen level. However, by altering kiln B to operate like kiln A and confining the operation of both of these kilns to the low part of the emission range substantial reductions in the emissions could be made. An emission factor of 2.1 lb of NOx as NO_2 per million Btu could be achieved in kilns A and B without the necessity of using a new set of conditions to make clinker. In order to achieve these lower emission levels it would be necessary to make tests to determine the emission characteristics of the units and set them up to operate at minimum emissions. New instruments and perhaps even new control devices may be necessary.

For the purpose of making comparisons between emission reduction techniques it is necessary to make cost estimates. The capital costs and the costs of the testing are assumed to be about $50,000 for each kiln. While there would be some maintenance for the new equipment there would also be some fuel savings. The two are considered for the purposes of this report to cancel each other (see discussion Section 11). If the capital cost were annualized at the rate of 20% per year, the annual cost would be $10,000 per kiln. Using the estimated new emission factors and the ones obtained from the measurements an emission reduction of 2500 tons per year might be achieved on the four kilns. Dividing the 5,000,000 pounds per year by $40,000 (4 x $10,000) results in a cost effectiveness ratio of 125 pounds NO_2 reduced per dollar of annualized cost. This is approximately 100 times more cost effective than some of the automotive emission controls under consideration or implementation.

Alternate Fuel

Comparing the emissions of kiln A when firing oil to the emissions of this kiln when firing gas one sees oil fuel produces much less nitric oxide than gas fuel at least in this unit. It would probably be true that switching to oil from natural gas would reduce the nitric oxide emissions

from other kilns and devices requiring high air preheat and heat transfer to very hot materials.

By switching the four kilns to oil it is estimated that a reduction in annual emissions of 5386 tons per year could be achieved. The annual cost for this change could be estimated if one knew the cost differential between natural gas and oil. Assuming that the difference is $1.50 per MMB the annual cost would be $7,875,000. Dividing this cost into the estimated emission reduction of 10,772,000 pounds results in a cost effectiveness ratio of 1.36 lbs of NOx prevented/dollar differential fuel cost, about equal to automotive control examples in Section 11.2.

The change to oil for the sake of reducing oxides of nitrogen emissions would thus be only marginally cost effective at this time based on this oil cost differential (see discussion Section 11). However, the price differential may be less at a future time. More likely is that gas fuel will not be available to the cement manufacturers. In this case the necessary change from gas fuel will result in a reduction in emissions of oxides of nitrogen.

It has been announced that one of these plants is going to put in coal burning equipment. How the switch to coal burning will affect the emissions of oxides of nitrogen is not known, but it is suspected that emissions for coal would be more like that of oil than for gas (see F-2).

Stack Gas Treatment

Treatment of stack gases to eliminate nitric oxides, to the author's knowledge, has not been applied to cement manufacturing operations. Processes which involve the reduction of NO and NO_2 to N_2, H_2O and CO_2 by reacting the nitric oxides with a fuel, usually natural gas, over a catalyst have been developed.[62] These processes are used to treat the gases released from nitric acid manufacturing operations. The gases from the two processes have a couple of similarities: high NOx, and low O_2 (before dilution) which indicate they might be treated by the same process. They also have some differences, notably the small size particulate loading in the cement plant effluent gas which could poison the catalyst.

Mr. William T. McShea, Engelhard Industries made an estimate of the costs for a process to remove the NOx from the flue gas generated by cement production.[63] The estimate is based on data which are not complete and should be considered preliminary. It reads in part as follows:

"The basic catalytic reduction abatement system is described on our sketch A-17496, two (2) prints of which are enclosed (Figure F-6). We have based our design on the 100 ton/hr (feed) direct water-cooled cement kilns. Gases from the baghouse would be ducted to a 2,000 HP blower. Blower exhaust would discharge into the cold side of a gas-to-gas heat exchanger designed to raise the temperature from 800 to 1000°F by counter-current exchange with the exhaust gases coming from the catalytic reactor. Additional heat would be provided by a natural gas fired preheater to raise the gas temperature to the required minimum catalytic reactor inlet value of 1250°F. In the fixed bed catalytic reactor, oxides of nitrogen will be combined with methane to produce carbon dioxide, free nitrogen and water vapor. We are confident that sufficient efficiency can be designed into this reactor such that the exhaust gases will contain less than 200 ppm by volume NOx. Reactor exhaust at 1300°F will pass through the gas-to-gas heat exchanger, exiting at 1100°F. Some of this gas will be directly exhausted to atmosphere while the balance will be sent to the direct water cooler. Exhaust from the direct water cooler will be at 100°F and would be added to the cement kiln exhaust for dilution and cooling."

"We recommend that the existing air-cooled cement kilns be switched over to direct water cooling because air dilution requires additional fuel to burn out the oxygen contained in that extra air."

"The primary advantages of this catalytic reduction abatement system over direct or thermal incineration are as follows:

1. The lower operating temperature will allow lighter weight process unit constructions, thus saving on installation costs.

2. Lower fuel consumption will save on annual operating costs.

3. The shorter residence time required for the catalytic reactor to effect the reduction will minimize equipment dimensions.

4. The low temperature operation minimizes the possibility of carbon formation."
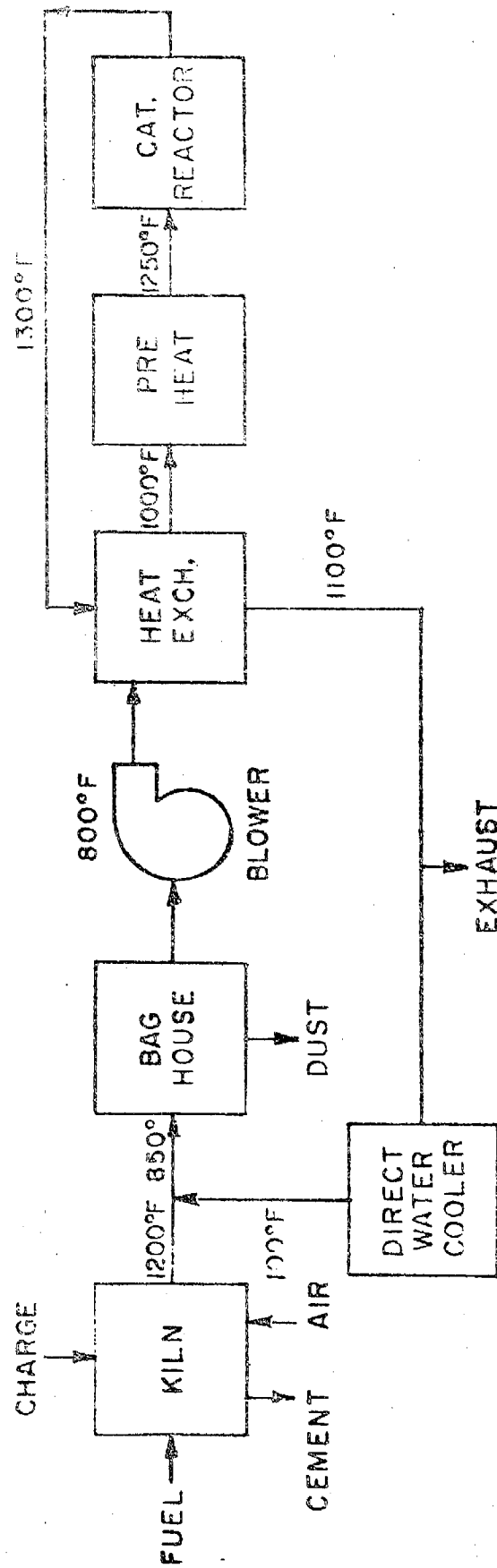
Figure F-6.

"We estimate the capital cost of the system described as follows:

Includes	Does Not Include
Blower/Motor/Starter	Installation
Heat Exchanger	Foundations
Preheater	Interconnection of
Catalytic Reactor	Electrical Utilities
Initial Catalyst Charge	
Piping	
Structural	
Engineering	
Freight	
Instrumentation	

Total..........$1,312,000 "

"The operating costs for this system, inclusive of fuel requirements, horsepower requirements, and one catalyst bed change per year, at approximately $500,000. We have assumed a fuel cost of $1.00 per million Btu, and $.89 per 100 horsepower-hour, operation of the cement kiln at 24 hours per day, 360 days per year."

It is assumed for the purpose of this report that the items not included are the field and home office expense represent 35% of the total plant cost. The total plant cost then becomes $2,020,000. The operational cost if one annualized capital cost at 20% per year, and 5% maintenance, is $500,000 plus $404,000 plus $101,000 or $1,005,000. For four units the cost would be $4,020,000 per year. The NO_2 emissions would be reduced to 828 tons per year. The reduction would be 9797 tons per year. The cost effectiveness would be 4.9 pounds of NOx as NO_2 eliminated per dollar total annual cost. See further discussion, Section 11.

Burner Changes

Changes in the burner operation or burner design could probably result in substantial reductions in the nitric oxide emissions. The

formation of nitric oxides from nitrogen and oxygen in the air is extremely sensitive to the peak flame temperature and the excess oxygen at the peak flame temperature. Very subtle changes in burner design and burner operation can frequently result in substantial reductions in nitric oxide emissions. It is anticipated that a burner which slowed down the mixing of air and fuel and produced a long drawn out flame could reduce emissions. The development of a burner which would operate safely and stably over the desired firing rate, produce desirable clinker and have low nitric oxide emissions could be expensive. However, the results could be significant, the operational costs minimal, with an overall attractive cost effectiveness ratio.

F-5   CONCLUSIONS

The annual emissions from cement manufacturing operations, the
four kilns discussed here, two small speciality cement kilns and five driers
were calculated to be 11,853 tons per year. This is about 8% of the total
annual emissions of nitric oxides from stationary sources in the Basin.
However, on a summer day the emissions from these two plants are about 10%
of the total emissions from stationary sources.

Reductions of 2500 tons per year could possibly be achieved by
changing the operation of the four kilns. Lowering the excess air might
accomplish this. This would be about 1.7% of the stationary emissions in
the Basin. The cost effectiveness is estimated to be 125 pounds per dollar.

It is estimated that a reduction of 5386 tons/year might be achieved
by switching the four kilns to oil fuel. This would be 3.6% of the emissions
from stationary sources in the South Coast Air Basin and 45% of the emissions
from cement manufacturing operations. The cost effectiveness ratio would be
about 1.4 pounds per dollar differential fuel cost.

A tail gas clean up process has been proposed. If it would prove
to be successful on the four units it would reduce emissions by 9797 tons
per year at a cost effectiveness ratio of about 4.9 pounds per dollar. This
would be 6.5% of the stationary source emissions in the South Coast Air Basin.

References

63.   Private Communication from William T. McShea, August 16, 1974.

64.   "Measuring the Environmental Impact of Domestic Gas-Fired Heating
      Systems," P.W. Kalika, G.T. Brookman, TRC Corp., APCA Paper, June 1974.

APPENDIX G

COMMERCIAL, INSTITUTIONAL AND INDUSTRIAL BOILERS

G-1   INTRODUCTION

This class of devices includes all boilers with a firing rate of
10 MMB/hr or more except electric utility boilers, those in refineries
and those in steel mills burning coke oven gas or blast furnace gas.
Boilers are used in industrial application to provide process steam and
in commercial/institutional applications primarily to provide steam for
heating and to drive turbines for air conditioning.

Since the walls of a boiler are cool relative to the temperatures
necessary for nitric oxide formations, the flame is quenched rapidly and the
residence time, during which the combustion products are at high temperatures,
is relatively short. The result is, combustion under these inherently
non-adiabatic conditions produces low concentrations of nitric oxide
relative to combustion under more nearly adiabatic conditions such as
found in internal combustion engines, furnaces, kilns, etc.

Emission factors for boilers in the category were available from
studies conducted by the LAC APCD[20]   and the EPA.[12]   However, it is
clear from the LAC APCD data and from the tests conducted for this program
that the NOx emissions from any individual boiler can vary considerably
from the emission factor. Among the factors contributing to this variation
are:

. Basic design differences in heat release area, burner configuration,
  number of burners, etc.

. Variation in operating procedures from plant to plant; for example,
  some operators attempt to minimize the flue gas oxygen levels,
  while others run at excessively high oxygen levels.

. Poor combustion control due to coarse control mechanisms and
  inaccurate or non-existant monitoring instrumentation.

. Presence or absence of air preheat.

. Differences in fuel nitrogen levels (significant for oil
combustion only)

Most boilers in this category use light oils such as #2 diesel
as the standby fuel during gas curtailment. Presumably, higher viscosity
residual oils are not used because of the handling problems associated
with oils that must be heated in order to be pumped and atomized. Since
oil supplied only about 4-7% of the total annual heat input for most of
these boilers during the 1972-73, it is apparently more cost effective to
burn the more expensive light oils than to install the necessary additional
fuel systems to handle the less expensive heavy oils.

There are about 530 of these boilers in the boiler inventory,
ranging in size from 10 MMB/hr to about 200 MMB/hr. Of these, all but about
10 are rated at 100 MMB/hr or less. About 20% burn only gas, about 70%
burn gas with distillate oil standby, and about 10% burn gas with residual
oil standby. In most industrial applications these devices are characterized
by high use factors. They tend to run 24 hours a day at a high percentage
of maximum design load ($\sim$ 80-110%). However there is typically a 20-50%
excess boiler capacity to allow full production with some of the boilers
out of service. This means that each boiler is on line 70-80% of the year
and down or on hot standby the remainder of the time. In most commercial/
institutional applications, boilers tend to run full time also, but at lower
loads ($\sim$ 20-50%). Generally there is a 50-100% excess boiler capacity
at these facilities with the result that each boiler is on line 50-70%
of the year. In both cases steam is typically generated all year, with
relatively minor seasonal load variations.

Although most of the boilers in the inventory were identified
from their APCD permits, an additional source was necessary to identify
boilers that are gas fired only (only devices that have oil standby are
under permit). Since the California Division of Industrial Safety maintains
records on all pressure vessels, their records were consulted in order to
identify boilers not under APCD permit. This task was considerably com-
plicated by the facts that all boilers, including many very small ones,

are included in their computer records and that there is no direct indication of firing rate in the records. By using the heat transfer area an estimate of firing rate was made; the actual firing rate was then provided by the operator via the questionnaire. (Section 4).

Since it was not possible to collect enough test data to develop a new boiler emission correlations, the goals of the boiler test program were:

- Check the applicability of the existing emission correlations with respect to a sample of the Basin population of boilers in this category.
- Determine the spread around these correlations due to the variables discussed above.
- Assess the NOx reduction possible by operational modifications (low excess air, etc.)

Most of the boilers selected for testing had a firing rate in the range 10-100 MMB/hr because nearly all of the boilers in this category fall in this size range. A few smaller boilers were tested in order to improve the data at the lower end of the size range.

All of the boiler tests were run on boilers burning natural gas (except for two refinery boiler tests), primarily because this category of devices are fired by natural gas except for a few days of the year when gas is curtailed. Although some tests on oil fuel would have been desirable no gas curtailment occurred during the test period and none of the operators would switch to oil for the tests.

MEASUREMENT OF NOx EMISSIONS FROM INDUSTRIAL AND COMMERCIAL/

INSTITUTIONAL BOILERS

A total of 94 tests were run on 34 boilers from this category during the test program. The results are tabulated in Appendix A of this report. Where possible the sampling was done in the stack, up stream of the air preheater, and at several locations. In some cases it was not possible to insert a probe any where in the exhaust ducting or stack. When this occurred an existing cold sampling line was used with subsequent loss of NO_2. (This loss was compensated for as described in Section 8.0.) In all cases the stack flow rate was calculated from fuel or steam flow measurements.

Tests at various loads and/or excess oxygen levels were done on 9 of the 34 tested boilers. In general the load variations were the result of changes in steam demand rather than systematic changes for test purposes. In a few cases, tests were run at various excess oxygen levels of a constant load. It was not possible in either case to conduct a systematic study of these variables.

Figures G-1 and G-2 are plots of hourly NOx emissions versus firing rate from gas and oil combustion, respectively. In addition to the test data from this program, data are presented from the concurrent EPA Industrial Boiler Program[24] and from the LAC APCD.[20] For comparison purposes, the size dependent emission correlation based on LAC APCD data[20] and the EPA recommended emission factor[12] are also shown.

The scatter in the data is typical of other such plots (see Figure 2-1 and 2-2) as discussed in Section 2.2. Almost all of the gas test points (from all three sources) fall within a band 50% lower to 100% higher than the LAC APCD correlation; most of the oil test data also falls within a similar band. Stated another way, most of the test data is within a factor of 2 higher and lower than the correlation.

Table G-I shows how the test values from all three sources compare with the EPA utility boiler new source standards of 0.2 lbs NOx/MMB for gas combustion and 0.3 lbs NOx/MMB for oil combustion.
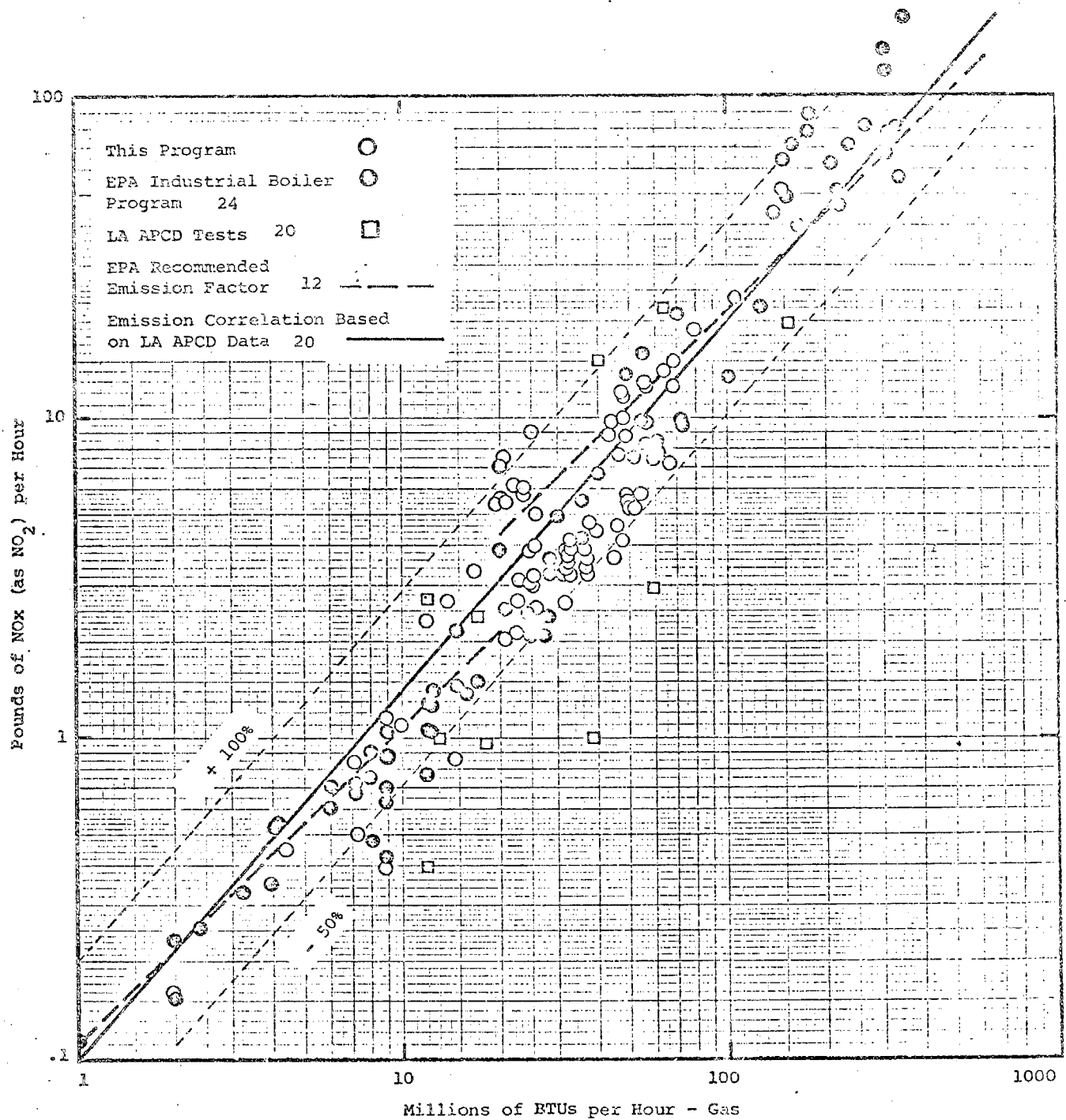
Figure G-1. Hourly NOx Emissions From Boilers Burning Gas

G-5

5800-179

Legend within figure:
- This Program ○
- EPA Industrial Boiler Program 24 ○
- EPA Recommended Emission Factor 12 ─ ── ─
- Emission Correlation Based on LA APCD Data 20 ──────

Y-axis: Pounds of NOx (as NO$_2$) per Hour

X-axis: Millions of BTUs per Hour - Oil

HHV 150,000 B/gal, × 100%, 50%
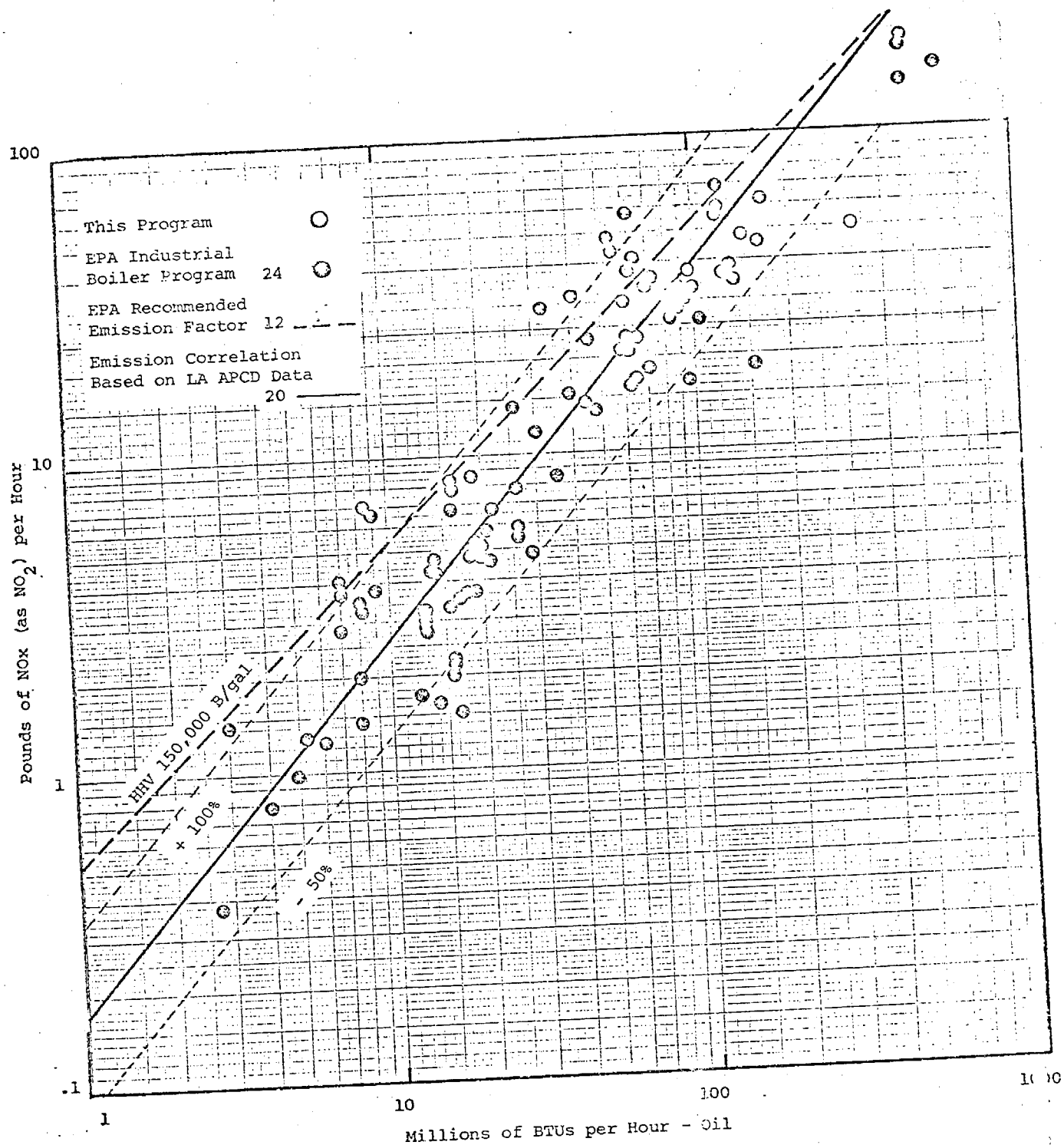
Figure G-2. Hourly NOx Emissions From Boilers Burning Oil

5800-17

G-6

TABLE G-I

PERCENTAGE OF INDUSTRIAL AND COMMERCIAL/INSTITUTIONAL

BOILERS THAT EXCEED EPA STANDARDS

CONSIDERING DATA FROM (24),(65) AND THIS PROGRAM

Firing Rate (MMB/hr)	% Of Test Points Exceeding EPA Standards	Fuel
0-10	0	Gas
10-100	22	Gas
100-250	80	Gas
0-10	56	Oil
10-100	51	Oil
100-630	53	Oil

The emission correlations based on LAC APCD data were used to calculate the emissions from this category of boilers for several reasons:

. For both gas and oil combustion they seemed to be most representative of the data (all three sources considered)

. For both gas and oil combustion they account for the size dependency which has been observed.

G-3   EMISSIONS INVENTORY

The emissions for all boilers in the inventory in this category, including those that were tested, were estimated using these correlations. The correlation values, rather than the actual test results were used on the tested boilers because there was no way to assure that the load and excess oxygen level at which the boiler was tested was truly representative of the boilers' operation over a year. If they were not, the test values would no longer be valid for the new conditions.

After the boilers were identified and the design heat rate was determined, the next largest uncertainties in calculating the emissions were related to duty cycle (fraction of time on line), and operating load fraction. Responses to the questionnaire (described in Section 4) provided detailed information that clarified these uncertainties and provided detailed fuel use information. This information was then used to calculate the emissions from each boiler individually.

The emissions from industrial and commercial/institutional boilers were calculated using the following equations:

Maximum hourly emission (lbs/hr)

Gas: $E_{HG} = .092 \, Q^{1.17}$

Oil: $E_{HD} = .175 \, Q^{1.17}$

Peak daily emissions (tons/day)

$$\text{Summer: } E_{DS} = (.012)(.092)(C_{FS}Q)^{1.17}(Ts/24)$$

$$\text{Winter: } E_{DW} = (.012)(.175)(C_{FW}Q)^{1.17}(Tw/24)$$

Annual emissions (tons/year)

$$E_{A} = .012 \left[(.092)(C_{FG}Q)^{1.17}(T/24)(D_{g}) + (.175)(C_{FO}Q)^{1.17}(Tw/24)(Do) \right]$$

where

E_{HG} = Maximum hourly emissions while burning gas, lbs/hr

E_{HO} = Maximum hourly emissions while burning oil, lbs/hr

E_{DS} = Average summer daily emissions, tons/day

E_{DW} = Average winter daily emissions, tons/day

E_{A} = Annual emissions, tons/year

Q = Maximum design firing rate, mmB/hr

C_{FS} = Capacity factor, summer

C_{FW} = Capacity factor, winter

C_{FG} = Capacity factor on gas

C_{FO} = Capacity factor on oil

Ts = Average fired hours per day, summer

Tw = Average fired hours per day, winter

T = (Ts + Tw)/2, average fired hours per day, on gas

D_{g} = Days per year burning gas

D_{o} = Days per year burning oil

Table G-II shows a breakdown by fuel types of boilers in this category:

TABLE G-II

BREAKDOWN OF BOILERS BY TYPE(S) OF FUEL USED

Fuels	Number	Size Range (MMB/hr)	% of All Boilers In This Category	Type
gas only	33	(10-73)	6	Commercial/Institutional
gas and distillate	189	(10-45)	35	Commercial/Institutional
gas and residual oil	26	(10-60)	5	Commercial/Institutional
gas only	59	(10-194)	11	Industrial
gas and distillate	189	(10-186)	36	Industrial
gas and residual oil	35	(10-66)	7	Industrial
	531			

Of these boilers, there are none in commercial/institutional applications that exceed about 73 MMB/hr and only about 15 in industrial applications that exceed 100 MMB/hr.

Table G-III presents the inventoried fuel use and NOx emissions for commercial, institutional, and industrial boilers other than in refineries as well as projections to 1975 and 1980. Having no specific data on growth in this category for the future, the projections were based on the forecast of percentage growth of energy requirements for "interruptible industrial" customers of the Southern California Gas Company as submitted to the Public Utilities Commission.[34] Emissions factors were retained as the same as in the 1972-73 inventory. Without an emissions control program the NOx emissions for this class of devices will grow to 8100 tons/year in 1975 and to 9800 tons/year in 1980. A significant portion of the growth is the direct consequence of forecast gas curtailment necessitating oil substitution for gas to the extent of about 32% in 1975 and 1980 as compared with only 10% in 1972/73.

TABLE G-III

FUEL USE AND NOx EMISSIONS PROJECTIONS FOR
COMMERCIAL/INSTITUTIONAL AND INDUSTRIAL BOILERS

Year	Gas (mmcf/yr)	Alternate Fuel (equivalent mmcf/yr)	NOx (tons/yr)
1972/73	49,500	2,700	5,500
1975	40,500	20,000	8,100
1980	51,500	23,200	9,800

Industrial and commercial/institutional boilers in the Basin, exclusive of refinery and electrical generation boilers which are discussed elsewhere in this report, emit about 5500 tons of oxides of nitrogen as NO_2 per year. This is about 3.5% of the emissions from stationary sources in the South Coast Air Basin. These emissions are produced by about units. Of these, the approximately 94 units with a firing rate of 50 MMB/hr or more emit about 2000 tons or about 40%. The average emissions per day per boiler for all boilers in this category is about 45 pounds.

In order to make cost effective emission reductions on devices emitting only 45 pounds an inexpensive device or technique is required. For instance, new automobile emission controls and retrofitted controls for all automobiles are expected to reduce emissions at cost effectiveness ratios of about 1.5 pounds of NOx as NO_2 eliminated per dollar annual cost. If the techniques eliminated 30% of the emissions from boilers emitting an average of 45 pounds per day the savings would average 13 pounds per day or 5000 pounds per unit per year. In order to achieve a cost effectiveness ratio in excess of 1 pound of NOx eliminated per dollar the annual costs would necessarily average $5000 per unit per year or less. If maintenance and operational costs were negligible and the capital was annualized at 20% per year, the capital would be limited to under $25,000.

For about $10,000 per boiler it is estimated that many boilers presently exceeding EPA new source standards could be set up to produce lower nitric oxides. For boilers with multiple burners this would probably be accomplished by reducing excess air and by staging combustion (see discussion Sections 11.3 and 11.4). From 1/4 to 1/3 of the burners would be removed from service. Air flow would be maintained through the out-of-service burners while the fuel flow to the remaining burners would be increased sufficiently to maintain a constant total fuel flow. In oil firing the tips are usually enlarged. The active burners then would have insufficient air to react with all the fuel. As a result the flame temperature would be lower and all of the oxygen would be consumed.

Then, after heat is lost to the boiler walls and the fuel rich products have cooled they mix with the air from the out-of-service burners and the remaining fuel is consumed. The desired result of reduced emissions is caused by the lower peak flame temperature and the lack of excess oxygen at the peak temperature. Nitric oxide formation is strongly dependent upon temperature and oxygen concentration as discussed in Section 2.1.

In the case of boilers with one burner, ports which bypass the burner must be made between the wind box and the boiler. These ports should carry 20 to 30% of the total air flow to the boiler. The cost for these ports may be of the order of $10,000 per boiler.

If for the $10,000 capital cost estimate the maintenance and operational charges are assumed to be negligible and capital cost is annualized at 20%, the annual charges are $2,000. To obtain a cost benefit ratio of 5, emission reduction of 10,000 pounds per unit would be required.

It is estimated that the emissions from this category of boilers burning only natural gas could be reduced by 50%, the emissions from those burning gas and oil could be reduced by 35%, and the emissions from those burning oil only could be reduced by 20%.

It has been estimated in Section 11.4 that boilers in this source category emitting in excess of 6000 lbs of NOx per year could be controlled through the use of staged combustion with a cost effectiveness ratio in excess of 1 lb of NOx prevented per dollar annual cost with these percentage reductions. Of the inventory of boilers in this category 75% of the boilers, emitting 90% of the emissions, have emissions rates in excess of 6000 lbs. Thus a reduction of about 35% of 5500 tons/year might be achievable by controlling these boilers.

G-5 CONCLUSIONS

The boiler tests confirmed that the emission correlations, developed from LAC APCD test data, which were used in the preliminary inventory, are applicable to the industrial and commercial/institutional boilers in the inventory.

The emissions from these boilers constitute approximately 3.5% of the annual emissions from stationary sources in the South Coast Air Basin. On summer and winter peak days emissions from these boilers constitute 4% and 3% of the daily emissions, respectively.

It is estimated that these emissions could be reduced by 35% by applying low excess air and staged combustion to 75% of the boilers in the inventory with a minimum cost effectiveness in excess of 1 lb NOx prevented per dollar annual cost. There appears to be no known method of reducing emissions from the remaining 25% of boilers at a cost effectiveness ratio as high as this.

References

12. "Compilation of Air Pollutant Emission Factors," Office of Air Programs Publication No. AP-42, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, February 1972.

20. "Emissions of Oxides of Nitrogen from Stationary Sources in Los Angeles County," A Joint District, Federal, State, and Industry Project, by J.L. Mills, K.D. Luedke, Paul F. Woolrich, and L.B. Perry, Reports 1-4, February 1960 - July 1961.

24. "Field Testing: Application of Combustion Modifications to Control of Pollutant Emissions from Industrial Boilers - Phase I," G. Cato, J.M. Robinson, KVB, Inc., EPA-650/2-74-078-a, October 1974.

34. "1974 California Gas Report," Prepared Pursuant to California Public Utilities Commission Decision 62260, July 1, 1974.

APPENDIX H

DOMESTIC AND SMALL COMMERCIAL/INDUSTRIAL SOURCES

H-1   INTRODUCTION

Combustion in domestic and small commercial/industrial devices, such as water heaters, space heaters, clothes dryers, etc., forms NOx in small cool combustion chambers. Although the oxygen readings at the stack typically run 15-17%, the stoichiometry of the flames is not represented by this oxygen concentration. Due to the type of natural draft involved not all of the oxygen that comes out of the stack has been available for combustion.

These devices are unique for two reasons: (1) they go through a large number of start-up and shut-down cycles, and (2) they usually operate at a constant load when operating, that is, they operate at one given load or they are off. Since the on/off cycles occur so frequently, any unusual NOx emission characteristics at either end of this cycle are significant. Most larger industrial devices, on the other hand, are started or stopped infrequently. However, all of the tests in this program on residential and commercial devices, indicate that the NOx emissions reach a steady state nearly instantaneously during both hot and cold starts, and that they go to zero nearly instantaneously during a shut down, whether the entire device is at operating temperature or not.

Due to the large number of devices in this category and the large number of types of devices, it was not possible to establish emission factors based on specific device type. Therefore, it was necessary that there be only one general emission factor for residential devices and one for the larger commercial devices. For these types of devices, the emission factors were applied directly to the fuel use and since the fuel use is accurately known, the accuracy of the emission estimates is determined only by the applicability of the emission factors selected to the whole population of devices to which they were applied.

The purpose of the domestic and small commercial/industrial device test program was to check the applicability of the EPA Recommended emission factor for such devices when burning gas.[20]   The EPA recommended factor for domestic devices was brought into question by the data obtained by the LAC APCD (Section 2, Figure 2-2). Most of the data points in the 20,000 Btu/hr to about 200,000 Btu/hr range fall considerably above the emissions values derived from the correlation equation. An average emission factor of about 0.09 lbs NOx/MMB was calculated for these data points, as compared with EPA factor of of about 0.05 lbs NOx/MMB for domestic devices. This value, however, was in good agreement with the EPA factor of about 0.10 lbs NOx/MMB for commercial devices.

In order to clarify this discrepancy, a series of residential devices were selected for testing. To provide a representative sample of common domestic devices, wall heaters, forced air heaters, water heaters, clothes dryers and a swimming pool heater were included in the test program. All of the tested devices were natural gas fired. Very nearly all of the residential combustion devices in the Basin burn natural gas. A small percentage of the residences in outlaying areas burn LPG. Essentially no other fuels are burned in residential devices.

The only commercial devices that were tested were 7 commercial building forced air heating units. Since this omits a large number of types of commercial devices (for example commercial ovens, paint drying ovens, commercial clothes dryers, etc.), a representative sample of commercial devices was not tested.

In all tests of residential and commercial devices the sample line was inserted into the exhaust stack far enough to assure that no ambient air was being mixed with the sample other than that induced into the stack above the combustion zone.

In order to get an accurate measurement of the heating rate, fuel flow to each device was monitored. This was accomplished by terminating the gas flow to all devices on a given meter except for the device being tested. The fuel flow was then determined by measuring the time necessary for a convenient volume of gas to pass through the meter. It was found that the actual heat rates where frequently different by as much as 20% from the name plate rate. Therefore, a fuel flow measurement was made in every case. The heating value of the fuel was taken to be 1050 B/ft^3.

Since most devices in the category are controlled by automatic control devices, the controls were bypassed in order to start and stop the device when desired. In the case of comfort heating the thermostat was set at a high enough or low enough setting to get the device to cycle. For water heaters, the hot water was turned on at several faucets in the building so that the heater came on by its thermostat control. In no case were the control devices disabled in a manner that allowed non-standard operation. The devices were all operated at normal temperatures.

All devices were tested in the "as found" condition. No attempt was made to tune up or otherwise alter the condition of the devices. It was felt that the sample would be most representative if this procedure were followed since it would be expeced that the condition of the general population of such devices would cover a range similar to that of those tested.

Table H-I lists the results of 31 tests on domestic and commercial devices. For domestic devices, the range of emissions is from 0.04 lbs NOx/MMB to 0.18 lbs NOx/MMB. If the two data points at the extremes are discounted the range is from 0.07 lbs NOx/MMB to 0.13 lbs NOx/MMB (this includes 29 out of 31 tests). The average for all 31 devices is 0.10 lbs/MMB.

TABLE H-I

NOx EMISSIONS TEST RESULTS FOR DOMESTIC AND
COMMERCIAL GAS FIRED APPLIANCES

Domestic Devices

Test #	Device Type	Heat Rate (B/hr)	lbs NOx (as NO_2)/ MMB
1	Wall Heater	33,000	0.13
2	Wall Heater	29,600	0.10
3	Wall Heater	28,100	0.10
4	Water Heater	38,900	0.12
5	Water Heater	42,400	0.13
6	Forced Air Heater	70,700	0.07
7	Water Heater	48,500	0.11
8	Forced Air Heater	109,600	0.09
9	Water Heater	37,800	0.09
10	Forced Air Heater	126,000	0.09
11	Water Heater	55,600	0.10
73	Forced Air Heater	126,000	0.09
74	Water Heater	42,000	0.12
75	Clothes Dryer	7,900	0.04
76	Forced Air Heater	121,900	0.13
77	Water Heater	42,000	0.09
78	Clothes Dryer	30,500	0.07
79	Water Heater	46,100	0.07
80	Forced Air Heater	128,100	0.10
81	Forced Air Heater	108,000	0.10
82	Forced Air Heater	84,000	0.13
83	Water Heater	42,000	0.11
90	Forced Air Heater	151,200	0.08
91	Water Heater	35,700	0.15

Domestic Devices

Test #	Device Type	Heat Rate (B/hr)	lbs NOx (as NO_2)/ MMB
92	Water Heater	35,700	0.08
93	Forced Air Heater	137,500	0.08
94	Forced Air Heater	112,800	0.09
95	Water Heater	43,000	0.11
178	Water Heater	36,700	0.07
179	Forced Air Heater	84,000	0.07
180	Pool Heater	216,000	0.18

Commercial Devices

Test #	Device Type	Heat Rate (B/hr)	lbs NOx (as NO_2)/ MMB
30	Forced Air Heater	126,000	0.11
30A	Forced Air Heater	63,000	0.06
30B	Forced Air Heater	126,000	0.10
30C	Forced Air Heater	126,000	0.10
30D	Forced Air Heater	100,800	0.12
30E	--	--	--
30F	Forced Air Heater	100,800	0.10
30G	Forced Air Heater	113,400	0.11
30H	--	--	--

For the commercial heaters, the range is 0.06 lbs NOx/MMB to 0.12 lbs NOx/MMB, with an average of 0.10 lbs NOx/MMB, also.

This consistency in the data is probably due to the facts that:

. Essentially all devices in both categories are natural draft units that entrain large amounts of excess air.

. Most burners in these devices consist of a series of small somewhat isolated flames; changes in design heat rate is usually accomplished by changing the number of these flames rather than their size.

. Most of these devices exhibit a similar degree of adiabaticity.

The results of this test program thus suggest an emission factor of about 0.10 lbs NOx/MMB for both domestic and commercial combustion devices. After the start of the test program, 2 reports were published which also tend to indicate an emission factor for domestic devices that is close to 0.10 lbs NOx/MMB. In the first of these,[53] 2 domestic furnace burners and a burner from a domestic boiler were tested in a common furnace combustion zone. The NOx emission rates were 0.07 lbs/MMB, 0.10 lbs/MMB and 0.10 lbs/MMB, respectively. In the second report[64] a series of 50 gas fired home heating boilers and 50 domestic forced air heaters were tested. In this case the average NOx emission rates were 0.10 lbs/MMB and 0.12 lbs/MMB, respectively. As was indicated earlier, most of the data in the 20,000 to 200,000 B/hr range in the LAC APCD[20] data correlation, fall substantially above the correlation line and that an average emission factor of 0.09 lbs NOx/MMB was calculated for the devices in this range.

These data tend to indicate that a minimum emission rate is reached at devices with design rates below about 200,000 B/hr. That is, below this size, the emission rate remains essentially constant regardless of size.

Since these data taken together support the selection of an average emission factor of about 0.10 lbs NOx/MMB, the emissions from residential sources was calculated using this factor. In the preliminary inventory, the emission factor used was the EPA recommended 0.05 lbs NOx/MMB. The result of this change is that Basin residential sources are now estimated

to emit twice as much NOx as was estimated for the preliminary inventory.

The EPA recommended factor of about 0.10 lbs NOx/MMB for commercial devices was supported by the limited test data taken for this program. In the absence of any additional data, this factor was used to estimate NOx emissions from commercial sources.

Since no tests were run on small industrial devices, the EPA recommended factor of about 0.15 lbs NOx/MMB was used to estimate emissions from these sources.

H-3   INVENTORY RESULTS

The NOx emissions from residential sources were determined by applying the emission factor to the residential gas use. The annual emissions from residential sources are about 14,280 tons/year, 18 tons/day for an average August day and 62 tons/day for an average December day. NOx emissions from these sources constitute about 9% of the annual emissions from stationary sources in the Basin and about 5% and 11% of the average August daily and average December daily emissions, respectively.

The annual NOx emissions from commercial sources are about 3,525 tons/year, 6 tons/day for an average August day, and 13 tons/day for an average December day. NOx emissions from these sources constitute about 2% of the annual emissions from stationary sources in the Basin.

Table H-II shows the projected gas use and NOx emissions by area sources for the years 1975 and 1980. (Area sources are those that are treated in aggregate rather than as individual devices.) These estimates were obtained from projections of "Firm - Retail" gas use as listed in a report on current and future gas use submitted to the California Public Utilities Commission.[34] It was assumed that the percentage of gas use by each category, relative to the total "Firm - Retail" gas use, will remain constant. (For the 1972/73 period residential, commercial and industrial area sources consumed 54%, 13% and 8%, respectively, of "Firm - Retail" gas.) The gas use by the categories for 1972/73 was obtained from gas company data (see Section 3).

According to these projections, if devices in these categories are not controlled, NOx emissions for 1975 will increase about 1% relative to the 1972/73 base period and about 20% relative to the base period by 1980.

H-4   REDUCTION POTENTIAL

Based on data from the Southern California Gas Company for Orange County for 1972, gas use per residence averages about 0.11 mmft^3/year (total residential gas use divided by the number of meters). This corresponds to annual average NOx emissions of about 12 lbs per residence per year. If it is desired that the annual NOx emissions from each device be reduced by 50% at cost effectiveness ratio no less than 1 lb of NOx per dollar (see Section 11), reduction would have to be accomplished at an annual cost of no more than $6. Annualized at 20% (as in other examples in this study) the capital cost would be limited to $30 per residence. If annualized at 16% per year (corresponding to a 10 year furnace life 10% interest) the allowable capital cost is $38 which is still substantially below what it would cost to change burners in an existing furnace.

Even if some modification or adjustment procedure were known, that would reduce by half the cumulative emissions from all domestic combustion devices (heaters, water heaters, stoves, etc.), it is highly improbable that the labor costs for a technican to do the adjustments for the several devices per residence could be held to $38 or less.

The only alternative seems to be to require the manufacturers of domestic combustion devices to meet emission regulations before the devices can be sold. The devices would have to be designed so that they are inherently low NOx emitters without increasing their costs beyond the limits suggested above. However, the approach would of course require a number of years to implement since devices in the residential category typically have   useful lives of 5-15 years.

TABLE H-II

GAS USE AND NOx EMISSIONS PROJECTS FROM AREA SOURCES

Year	Gas Use, mmft^3/yr	Tons NOx/yr
1972/73		
Residential	273,105	14,338
Commercial	67,162	3,526
Industrial	39,073	3,077
Total	379,340	20,941
1975		
Residential	274,400	14,400
Commercial	67,500	3,500
Industrial	40,200	3,200
Total	382,100	21,100
1980		
Residential	322,600	16,900
Commercial	29,300	4,200
Industrial	46,200	3,600
Total	448,100	24,700

Low NOx burners for devices of this type are under development. It is not known at this time how effective they will be in reducing NOx emissions, nor whether the costs can be maintained low enough to be attractively cost effective.

It is more difficult to make meaningful estimates regarding reduction potential for commercial and small industrial devices since they encompass such a wide variety of device types. However, since devices in these categories contribute only about 4% of the NOx from stationary sources, regardless of the degree of reduction actually achieved, the impact on the overall Basin NOx emissions would be very small.

H-5   CONCLUSIONS

The NOx emissions from residential devices constitute approximately 9% of the annual emissions from stationary sources in the South Coast Air Basin. On an average summer day emissions from these sources constitute about 5% of the stationary emissions, and on a winter day about 11%. Commercial and small industrial emissions average about 2% each of the total stationary emissions. For both cases, the average summer and average winter daily emissions average 2% of the total.

There is probably no cost effective way to reduce emissions from existing residential sources due to the large number of these sources and their small individual emissions. Use of low NOx burners in new and replacement residential units may be cost effective, but the relatively long life (5-15 years) of these types of devices mades replacement of existing devices a slow process.

Due to the variety of types of devices in the commercial and small industrial category, it is difficult to make meaningful estimates of reduction possibilities. However, since these sources emit only a total of about 4% of the NOx from stationary sources in the Basin even a large reduction would have only a very small impact.

References

20. "Emissions of Oxides of Nitrogen from Stationary Sources in Los Angeles County," A Joint District, Federal, State, and Industry Project, by J.L. Mills, K.D. Luedke, Paul F. Woolrich, and L.B. Perry, Reports 1-4, February 1960 – July 1961.

34. "1974 California Gas Report," Prepared Pursuant to California Public Utilities Commission Decision 62260, July 1, 1974.

53. "A Study of Air Pollutant Emissions from Residential Heating Systems," R.E. Hall, J.H. Wasser, E.E. Berkau, EPA-650/2-74-003, January 1974.

64. "Measuring the Environmental Impact of Domestic Gas-Fired Heating Systems," P.W. Kalika, G.T. Brookman, TRC Corp., APCA Paper, June 1974.

APPENDIX I

GLASS PRODUCTION

I-1   INTRODUCTION

Manufacture of glass in the South Coast Air Basin results in oxides of nitrogen emissions as NO_2 of about 4500 tons per year. These emissions are from 22 devices. The 4500 tons represent about 3% of the oxides of nitrogen emitted from stationary sources in the South Coast Air Basin. The gas consumption is about 1.3% of the gas consumption in the Basin and almost no oil is used. Half of these 22 devices emit about 3/4 of this amount. The major emitters in this industry are glass furnaces or melters as they are called.

Glass is produced by melting a mixture of silica (usually sand), sodium carbonate (soda ash), and other materials such as sodium sulfate, limestone, etc. Glass which may be cut at 200°F is actually brought to about 2750°F in the melter. In order to efficiently produce the product it is necessary to use combustion air which is preheated to a very high temperature. Air preheat temperatures of 1500°F and higher are sometimes used. This is accomplished by bringing the air in through a regenerative air preheater. The preheater is an expanded array of bricks known as checkers. There are checkers on either side of the furnace. The air is brough in through hot checkers, burned with fuel, heats the melt and passes out through the other checkers heating them up. After a time, for instance, 30 minutes, the air flow is reversed and the recently heated checkers warm the air while the hot flue gas rewarm the other checkers. Figure I-1 shows the layout of a glass melter with a flow of air. This unit has both a forced draft fan and induced draft fans. The induced draft fans drive ambient air which is passed through a venturi drawing the hot flue gas up the stack.

The desired result of the extensive air preheat is a high flame temperature. One result of high flame temperatures is high emissions of oxides of nitrogen.
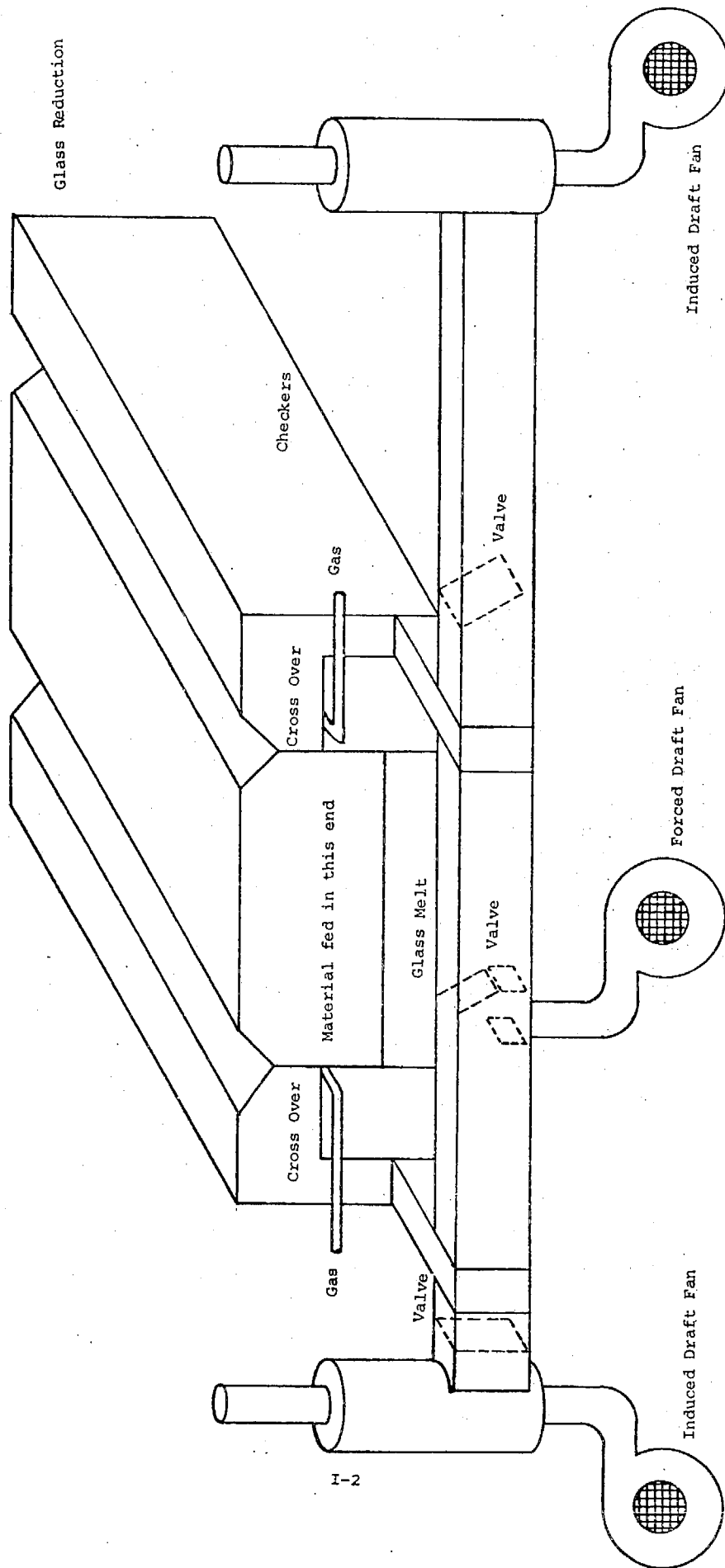
Figure I-1. Glass Melter

5800-179

Only one glass manufacturing device was tested during the present program. Testing was scheduled for a number of devices but all of the plants scheduled except the one tested were on strike at the time of the tests and were shut down.

I-2 MEASUREMENTS OF NOx EMISSIONS FROM GLASS PRODUCTION SOURCES

Both the sodium carbonate (soda ash) and the calcium carbonate (lime stone) used in the manufacture of glass give off CO_2 when the glass is being produced. This material dilutes the flue gas and reduces the measured concentration of oxides of nitrogen. It is therefore necessary to find the feed rate and composition and from these, calculate the amount of CO_2 coming out of the melt, or measure the gas flow rate and concentration of nitric oxide.

The gases coming from the checkers are too hot to handle with fans so the induced draft fans use ambient air to create a draft up the stack. The ambient air dilutes the combustion air. When samples are taken from the stack they are thus diluted with a large amount of air. This makes it difficult to follow the oxides of nitrogen as a function of excess combustion air.

One glass melter was tested for nitric oxide emissions. Table I-I shows the results. The oxygen level is much higher than it is in the furnace because of the dilution.

TABLE I-I

Emission Data

Device	Gas Fuel Flow 1000's of CFH	Feed Rate lb/hr	Flue Gas O_2, %	Stack Flow Rate SCFM	NO Measured ppm
Glass Melter	50	24,850	12.3-13.	25,235	192-219

Using the data the emissions for this unit were calculated on a pounds
per million Btu basis. The results of the calculations are shown in
Table I-II.

TABLE I-II

Emission Factors

A	B	C	D	E	F
Fuel Use	NO ppm	Stack flow in	NO, ft^3/hr	NO as NO_2 lb/hr	NO as NO_2
10^6 Btu/hr	average	10^6 ft/hr	BxC		lb/10^6 Btu
50	203	1.514	307	39.4	0.788

For the single unit which was tested the emissions were assumed to
be the average of the values found. Since the sample size was one, no
attempt was made to use this data to establish emission factors for other
units. Also, this unit was partially heated by electrical energy which
probably made it a lower emitted. Measurements made by the Los Angeles APCD[65]
where available were used. In inventorying the emissions from this source
category, for units not tested, the average of all the tests by the Los
Angeles APCD were used. The average value was found to be 1.9 pounds of
NOx as NO_2 per million Btu. Values ranged from 0.85 to 4.15.

I-3   GLASS PRODUCTION SOURCE NOx INVENTORY

The inventory was made by using the emissions data measured for specific units by the Los Angeles APCD and the fuel use data supplied by the glass manufacturers in their response to the fuel use questionnaire sent out for this program (Section 4.0).

The emissions from glass manufacturing were found to be about 4500 tons per year or 3% of the total. On a winter day the emissions are 10.8 tons or about 2% of the total. On a summer day the emissions are 12.2 tons or about $3\frac{1}{2}$% of the total. Glass furnace emissions do not change much from winter to summer because they seldom change from natural gas and when they do they usually change to a fuel such as diesel or even LPG.

In the future there may be little or no natural gas to burn in glass melters. At that time they will burn oil. No data on emissions of nitric oxide from these glass furnaces while burning oil is available. Devices with very high air preheat and nearly adiabatic flames are not expected to have higher emissions when firing oil. In fact devices such as these may have lower NOx emissions when firing oil (see results Appendix F).

The formation of nitric oxide in flames is a function of oxygen concentration. This is particularly true of flames in very hot devices such as kilns and steel making furnaces, etc. One way to reduce the emissions from a device such as a glass melter would be to reduce the oxygen in the furnace to very low levels. The oxygen level desired would be the lowest possible. To operate near this level would require more accurate instrumentation and controls to measure oxygen concentration in the flue gas or preferably oxygen concentration in the furnace. A dual set of instruments and controls would be needed since it would be necessary to control the oxygen when the furnace was firing from either direction. The samples should be taken very near the furnace discharge to avoid high readings due to air leaking into the flue system. For the purposes of making comparisons an estimate of the cost of the modifications is necessary. It is estimated that the investment for the modifications to a glass melter would be about $125,000 mostly for instruments and controls. While there would be some maintenance costs there would also be some savings in fuel. The two items might be comparable so neither will be included. In order to arrive at an annual cost for the purpose of this report an annualization of capital cost at 20%/yr was chosen. Thus the annual cost could be $25,000 per unit. If the eight units which produce the most oxides of nitrogen in the Basin were modified an average emission reduction of 30% might be made on these units. This would be 1,900,000 pounds per year. The cost effectiveness ratio would be 9.5 pounds per dollar annual cost. This cost effectiveness ratio is significantly better than the ratio found for current automobile emission control programs (as discussed in Section 11). This reduction would be 20% of the emissions from glass manufacturing and 0.6% of the emissions from stationary sources in the South Coast Air Basin.

Another way that the emissions from glass production plants can be reduced is to supply part of the energy as electrical energy, boosting. By supplying about 12% of the total energy consumed, but not necessarily

effectively used by the process, substantial reductions in the NOx emissions can be made. Boosting is sometimes used to increase melter capacity and/or to reduce particulate emissions. However, here it is considered for its value as an NOx emissions reduction technique.

The emissions from a melter already operating at reduced oxygen concentration were reduced from about 100 pounds to 40 pounds an hour of NOx as NO_2 when boosting at a rate of about 12% was initiated. The costs of operation are estimated for this report at

Annualized capital cost

$250,000 x 0.20 = $ 50,000

Increased rebricking frequency (maintenance)

$1,000,000/4 yr - $1,000,000/7 yr = $107,000

Electrical energy use

21,900,000 KW-hr x $.01/KW-hr   = $219,000

Fuel savings

12.5 x 10^6 Btu/hr x $.5/$10^6$ x 8760 h = $(54,750)

$321,250

The actual NOx savings in the Basin are the reduction at the glass factory less the amount emitted by the electrical generation necessary.

60 lb/hr x 8760 hr =   525,600
less   65,600
                                              460,000 lb/year

The cost estimated effectiveness ratio is 1.4 lb of NOx as NO_2 eliminated per dollar operating cost.

If the procedure were applied at the same time as low excess air combustion the overall reduction would be 1,844,000 pounds per year and the cost would be about $350,000 per year. The reduction would be at a cost effectiveness ratio of 5.3 pounds per dollar.

It is estimated that this procdure could be applied to eight units and in combination with low excess air combustion the reduction would be 1750 tons per year at a cost effectiveness of about 3. This is about 40% of the emissions from glass melters in the South Coast Air Basin and about 1.2% of the emissions from stationary sources in the Basin.

The natural gas is sometimes mixed with a small amount of air before it goes to the burner blocks. The air could be replaced with flue gas. Mixing flue gas with the fuel will reduce the flame temperature. A mixture of about 2:1, flue gas to fuel should reduce the emissions dramatically. It must be determined whether or not such a reduction in flame temperature could be made compatible with the glass production process,however.

I-5   CONCLUSIONS

The annual emissions from glass manufacturing operations are about 4500 tons. About 3/4 of this amount is emitted by 1/2 of the 22 units involved.

It has been estimated that the emissions from glass manufacturing operations could be reduced by about 20% by the use of low excess air combination on eight of the units. The cost effectiveness ratio was estimated at 9.5 pounds of oxides of nitrogen eliminated per dollar operating cost. It is estimated by the combining of low excess air combustion and electrical heating, boosting, the emissions from glass furnaces could be reduced by 40%.

The glass manufacturers may be forced to switch to oil or LPG fuel due to anticipated future shortage of natural gas. Just how this will affect the NOx emissions is not known since measurements with these types of fuels in these units were not made for this program and the LAC APCD did not have any oil fired data for glass melters. The change may, however, reduce emissions since oil flames tend to produce less nitric oxides than gas flames under the most severe conditions (see Appendix F).

In the absence of a basis for anticipating change, emissions from glass manufacturing are estimated to be constant through 1980.

Reference

65. Los Angeles County Air Pollution Control District Source Tests C1092, C1977, C1370, C1814, C1816, C2007, C1592, C978, C1984, C1684, C2006, C1356, C1809, C1216, C1554, C2027, 1965-1973.

APPENDIX J

INTERNAL COMBUSTION ENGINES

J-1   INTRODUCTION

The emissions from reciprocating internal combustion (IC) engines are a result of a non-steady combustion process that occurs at high temperatures, pressures and oxygen concentrations. These factors result in very high NOx emissions. The EPA emission factors for IC engines are 3.70 lb NOx/MMB for natural gas combustion and 2.70 lb NOx/MMB[23] for distillate oil combustion. These factors can be compared to 0.20 lb/MMB and 0.30 lb/MMB for gas and oil combustion, respectively, in a 100 MMB/hr boiler. Because of the high emission factors and large number of engines in the inventory, it was decided to test several engines to verify the quoted emissions.

Emissions from gas turbines are a result of combustion at lower pressures and relatively low oxygen levels than for reciprocating engines, followed by quenching with large volumes of cool air. These factors result in relatively low NOx emissions; 0.34 lbs/MMB for both gas and oil combustion.

There are three main industrial users for reciprocating IC engines in SCAB: (1) gas field operations use such engines as gas compressors, (2) the gas company uses these devices as pipe line and storage compressors, and (3) sewage treatment plants use digester gas-fueled engines to drive pumps, compressors and A.C. electrical generators (digester gas, which is a product of bacterial action on sewage, is approximately 65% methane and 35% carbon dioxide).

The location and census of these devices was provided by the oil companies,[35-41] the Southern California Gas Company[33] and the sewage treatment plants in the Basin.

The major use of gas turbines (other than those used by the electric utilities as peaking units) is as emergency standby electrical generators. The telephone company operates most of these devices and they provided the locations of their units.

As discussed previously the purpose of the IC engine test program was to verify existing emission factors for reciprocating engines and to assess possible control approaches for applicability to this source class. No gas turbines were selected for testing because the emissions from them are minor due to their very limited operating time.

In order to obtain a good cross section of IC engines, tests were scheduled on a variety of engine sizes and types. The eleven engines tested ranged in horsepower from 180 bhp to 2000 bhp. Since most of the industrial engines burn only gas, all the engine tests were run on gas fueled engines. The majority of the engines available for testing were two cycle, naturally aspirated. Some four cycle, turbo charged and supercharged two cycle engines were tested.

J-2   MEASUREMENT OF NOx EMISSIONS FROM INTERNAL COMBUSTION ENGINES

Due to the stack arrangement on the tested engines no sample ports were needed. The sample probe was inserted far enough into the exhaust pipe to assure that no ambient air was mixed with the sample. The stack flow rate was calculated from the fuel flow and the oxygen concentration as discussed in Section 8.0. In the cases where fuel flow rate was not measured, it was estimated from the power and heat rate. The heating value of the fuel was assumed to be 1050 B/SCF, and the heat rate as 7150 B/BHP-hr, based on typical engine efficiencies.

As was frequently the case, it was difficult to get the plant operators to vary the load over any substantial range. Some minor variations in load were possible in a few of the cases, but little load range data was obtained.

The results of the engine tests are summarized in Table J-1. Figure J-1 shows the relationship between the test results for 2 cycle engines and the EPA[23] recommended emission factor. The data from the two series of tests conducted for this study and independent tests conducted by LA APCD,[66] show considerable scatter. In general the EPA factor is higher than the results of these tests.
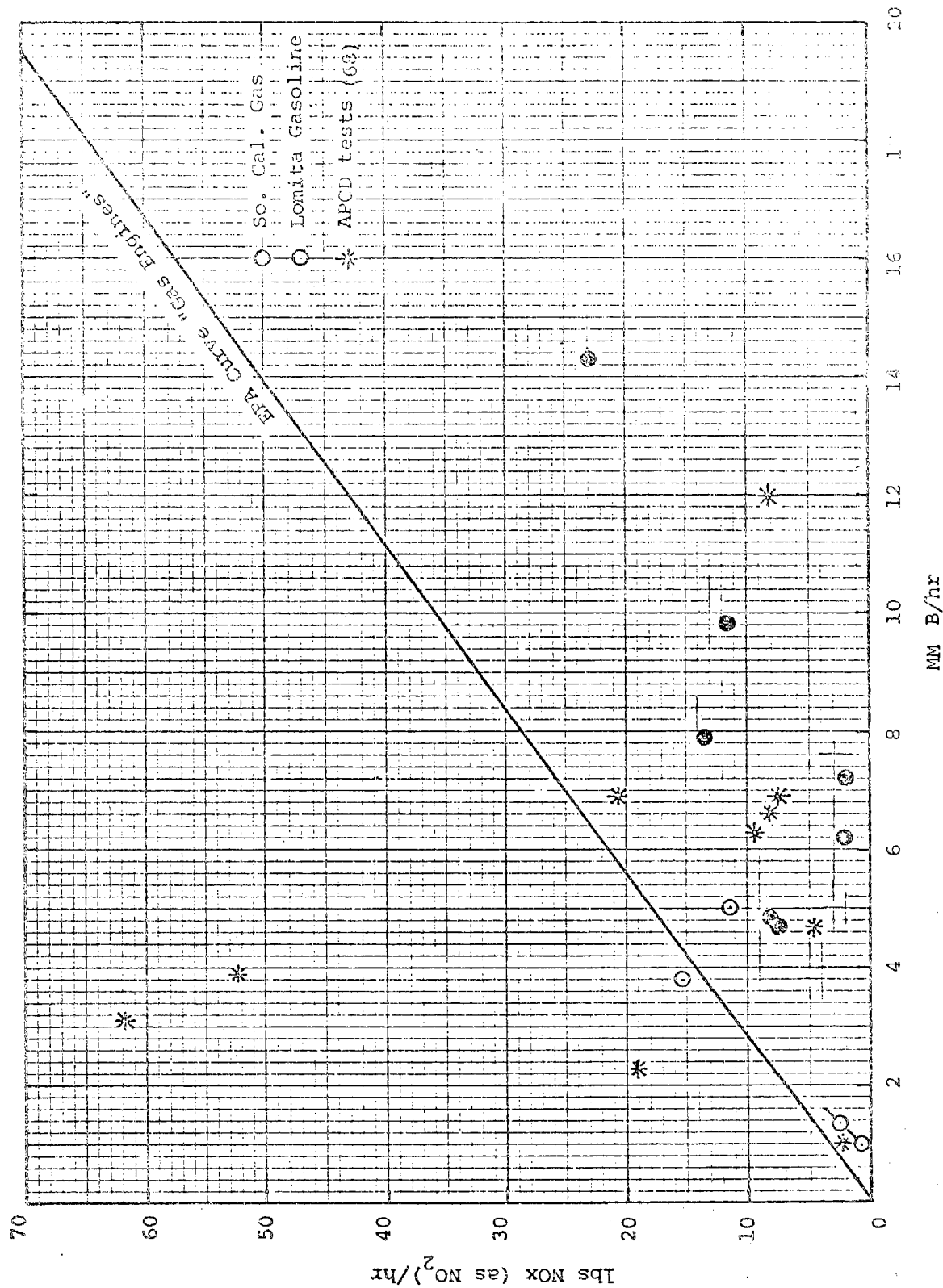
Figure J-1. Emissions From Gas Fired Internal Combustion Engines

TABLE J-1

NOx EMISSIONS FROM GAS FUELED INTERNAL COMBUSTION ENGINES

Test #	Engine Type	Rated H.P.	Test H.P. (MMB/hr)	lbs NOx (as NO_2)/MMB	lbs NOx (as NO_2)/hr
19	4,NA	600	∿600 (4.3)	.28	1.2
28,29	4,NA	550	∿550 (3.9)	.95-3.30	3.7-12.9
313	4,NA	660	670 (4.8)	1.70	8.2
314	2,NA	660	660 (4.7)	1.70	8.0
315	2,SC	1350	1350 (9.7)	1.17	11.4
316	2,SC	1350	1000 (7.2)	0.28	2.0
317A	2,TC	2000	2000 (14.3)	1.62	23.2
319	2,NA	1100	1100 (7.9)	1.74	13.8
330	2,NA	180	180 (1.3)	1.81	2.4
331	2,NA	180	144 (1.0)	0.46	0.5
332	2,NA	880	704 (5.0)	2.26	11.4
333	2,NA	660	528 (3.8)	4.05	15.3
			Average	1.64	

Engine Type

4,NA   4 cycle, naturally aspirated

2,SC   2 cycle, supercharged

2,TC   2 cycle, turbo charged

2,NA   2 cycle, naturally aspirated

The primary reason for lower emissions appears to be that these engines were operating in the lean regime (high air-fuel ratios). Figure J-2 is a plot of nitrogen oxide concentration versus exhaust oxygen concentration for the two cycle engines tested. A marked reduction from levels corresponding to the EPA factor (1500-3000 ppm) is seen to occur as the exhaust oxygen concentration is increased. Increases in exhaust oxygen concentration are indicative of leaner combustion and possibly, less efficient exhaust gas scavaging, both conditions resulting in lower NOx production. [23] Whether this condition is a result of leaner injector settings or poor engine condition is not clear, however it does point to a possible technique for emission reductions.

It is of interest to note (Tests 315 and 316) that reducing the load about 25% on one of the tested engines reduced the NOx emission rate from 11.4 lbs/hr to 2.0 lbs/hr a factor of almost 6.

This effect is in agreement with trends reported in Reference [23] for two cycle engines as BMEP (or load) is decreased. This change generally results in leaner combustion which is the primary mechanism for lower NOx production.

Since the lower NOx levels of the test results appeared to result from possible non typical deviations from normal (close to stoichiometric) operation it was decided to use the EPA factor to predict NOx emissions for the final inventory. The EPA factor, it should be noted, is about twice as high as the average of the results of the engines tested in this program. The emission equations used to estimate the emissions from reciprocating internal combustion engines are:

Maximum hourly emissions (lbs/hr)
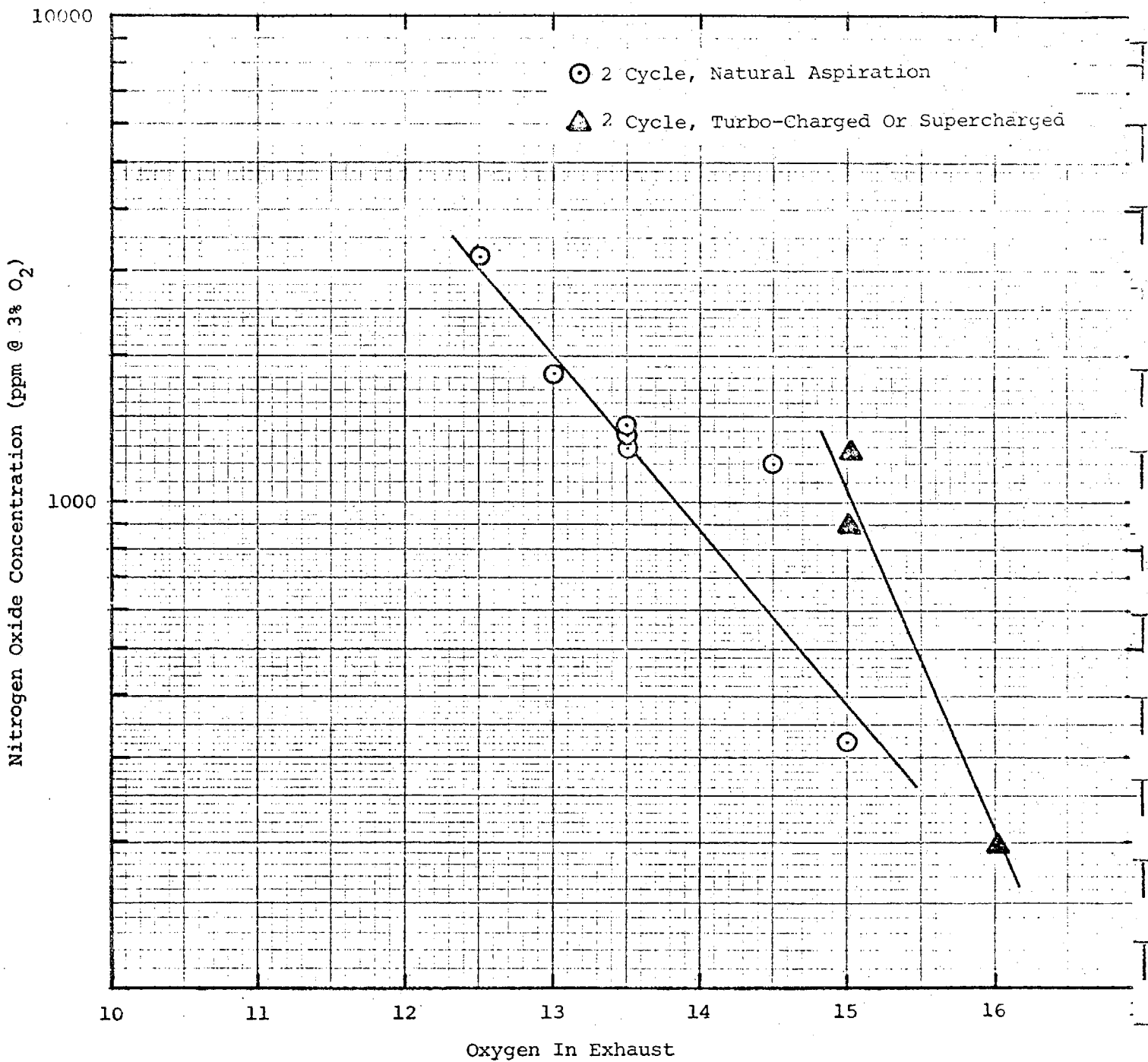
$$E_{HG} = 3.70Q$$

$$E_{HO} = 2.70Q$$

Figure J-2. Influence Of Excess Oxygen On Measured Nitrogen
Oxide Emissioms From Two Cycle Engines

5800-179

Average daily emissions (tons/day)

Gas fueled engines:

$$E_{DS} = (.012)\ (3.70)\ (C_{FS}Q)\ (T_S/24)$$

$$E_{DW} = (.012)\ (3.70)\ (C_{FW}Q)\ (T_W/24)$$

Oil or gasoline fueled engines:

$$E_{DS} = (.012)\ (2.70)\ (C_{FS}Q)\ (T_S/24)$$

$$E_{DW} = (.012)\ (2.70)\ (C_{FW}Q)\ (T_W/24)$$

Annual Emissions

Gas fuel engines:

$$E_A = (.012)\ (3.70)\ (C_{FG}Q)\ (T/24)\ (D_g)$$

Oil or gasoline fueled engines:

$$E_A = (.012)\ (2.70)\ (C_{FO}Q)\ (T/24)\ (D_o)$$

where:

Q = heat rate, mmB/hr

E_{HG} = maximum hourly emissions when burning gas, lbs/hr

E_{HO} = maximum hourly emissions when burning oil or gasoline, lbs/hr

E_{DS} = average daily emissions, summer, tons/day

E_{DW} = average daily emissions, winter, tons/day

C_{FS} = capacity factor, summer

C_{FW} = capacity factor, winter

C_{FG} = capacity factor, burning gas

C_{FO} = capacity factor, burning oil

T_S = hours per day on line, summer

T_W = hours per day on line, winter

T = $(T_S + T_W)/2$

D_g = days burning gas

D_o = days burning oil

Since individual tests were run on the IC engines at the sewage treatment plants by LAC APCD [66] individual emission factors were available for these engines. These devices are unusual because they burn a low Btu fuel (550-600 B/ft^3).

For gas turbine engines, the emissions calculations are (the EPA emission factor for both gas and oil fuel firing is the same):

Maximum hourly emissions (lbs/hr)

$$E_{HG} = E_{HO} = 0.34Q$$

Average daily emissions (tons/day)

$$E_{DS} = (.012)\ (0.34)\ (C_{FS}Q)\ (T_S/24)$$

$$E_{DW} = (.012)\ (0.34)\ (C_{FW}Q)\ (T_W/24)$$

Annual emissions (tons/year)

$$E_A = (.012)\ (0.34)\ [(C_{FG}Q)\ (T/24) + (C_{FO}Q)\ (T_W/24)]$$

Due to the limited data sample and limited load range data (i.e., NOx emission rate as a function of load), it was necessary to use the EPA generalized emission factor, rather than the test data, to estimate the emissions from all gas and oil burning IC engines in the Basin. The engines in the sewage treatment plants, however, were treated as separate cases because of the unusual fuel that they burn, and the availability of specific test data. The emissions from small turbine engines were calculated from the applicable EPA recommended emission factor since no tests were run.

Since stationary industrial internal combustion engines tend to occur in groups, and since in aggregate these devices contribute significantly to the total NOx emissions into the Basin (about 9%), their local impact can be substantial. That is, the NOx emissions from these engines is not evenly distributed throughout the Basin but is instead, concentrated in a few locations. On the other hand, most of the small turbines are used as emergency standby electrical generators and as such are more evenly distributed throughout the Basin. Also they are on line very infrequently and for short periods of time for test purposes. Therefore, the impact from these devices is minor.

Table J-II summarizes the emissions from internal combustion engines for the South Coast Air Basin. The total of 42.4 tons NOx/day represents 10% of the total. These engines for the most part are built to burn gaseous fuel only. Changes in gas supply should not affect future emission trends as priority must be given to firm gas supplies for these units.

TABLE J-II

ANNUAL EMISSIONS FROM INTERNAL COMBUSTION ENGINES IN THE SCAB

South Coast Air Basin, July '72-June '73

Type	Fuel	Source Entries	Number of Engines	Annual Emissions Tons/year
ICE	natural gas	84	436	14,163
ICE	digester gas	7	22	345
ICE	diesel	8	10	26
Turbine	oil	30	34	76
Turbine	natural gas/oil	16	47	861
		145	539	15,471

The reduction of NOx emissions from IC engines has been studied
quite extensively. McGowin has summarized the most promising methods
in Table J-III (after Table 20 of Reference 23). In   general these are
categorized as engine modifications and exhaust treatment. Operational
engine modifications involve the lowest capital expense but may ultimately
be more expensive. Table J-IV (after Table 21 of Reference 23) summarizes
the effectiveness of various operational modifications on NOx emissions
and fuel consumption.

As can be seen cost effective NOx emissions reductions (see Section
11) (assuming $2.00/MMB fuel oil cost)*   can be achieved by operational
modifications alone. Values as high as 92 lb NOx/$ based on fuel costs
only were achieved for the experimental program reported in Reference 23.
Cost effectiveness based on the total of modification costs maintenance costs
and fuel costs would be only slightly lower. This result appears to be
supported by the test results on this program where, for example, small
increases in air-fuel ratio produced dramatic reductions in NOx. This
was observed both in the tests of two cycle engines and in the test of a
four cycle engine where changes from about 2700 ppm to 770 ppm occurred
during normal operating fluctuations. The author of Reference 23 states
that simultaneous measurement of air/fuel ratio trapped in the cylinder
show that this is the predominant mechanism for NOx reduction. No
explanation is given as to why an increase in air flow does not produce as
large a change as other parameter changes.

It should be noted that as a group the 4 engines tested at Lomita
Gasoline (operating on natural gas) had emissions factors somewhat closer to the
EPA[23] emission factor of 3.7 lb NOx/MMB than did the group of 7 SCEC engines
tested. It is not known at this time whether the SCGC engines had undergone

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*Assuming that any lost energy resulting from loss of fuel efficiency would
eventually have to be made up with oil somewhere in the Basin under a limited
(inadequate) gas supply.

TABLE J-III

EMISSION CONTROL METHODS FOR RECIPROCATING ENGINES

I. Engine Modifications

  A. Operating Conditions:
    1. Speed
    2. Torque/Load
    3. Air/Fuel Ratio
    4. Ignition Timing
    5. Fuel Injection Timing
    6. Air Temperature
    7. Air Pressure
    8. Exhaust Back Pressure

  B. Engine Hardware:
    1. Exhaust Recirculation
    2. Water Injection
    3. Valve Timing
    4. Combustion Chamber - Stratified Charge
    5. Compression Ratio

II. Exhaust Treatment

  A. Exhaust Thermal Reactor (CO/HC)

  B. Catalytic Converter:
    1. Oxidation (CO/HC)
    2. Reduction of NOx by CO, H_2, NH_3, or natural gas

TABLE J-IV

EMISSION CONTROL BY MODIFICATION OF OPERATING CONDITIONS

Cooper Bessemer GMVA-8 Two-Stroke Atmospheric Spark-Gas Engine

Operating Conditions	Mass Emissions (Grams/BHP-Hr)			Exhaust Conc (ppm$_v$)			Fuel Consumption (Btu/BHP-Hr)	Change From Base Values		Emission Factor lb NOx/MMB	Reduction Cost Effectiveness lb NOx/$
	NOx	HCT	CO	NOx	HCT	CO		NOx Emissions	Fuel Consumption		
Base Conditions a)	15.23	1.94	.29	1079	395	34	7079	-		4.7	
Retard Ignition 10° to 4° BTDC	12.75	2.26	.35	918	466	42	7496	-16.2%	+5.8%	3.7	8.6
Increase Air Flow 161 to 201% Displacement	14.66	2.14	.22	842	352	21	7223	-3.7%	+2.0%	4.5	5.0
Decrease Air Manifold Temp 130 to 80°F	8.09	2.19	.34	574	446	40	7169	-46.9%	+1.2%	2.5	92
Increase Exhaust Back Pressure 0 to 6" Hg	9.53	2.16	.30	686	447	36	7673	-37.4%	+8.4%	2.7	11.9
Increase Speed at Constant BHP 300 to 330 RPM	6.41	2.24	.41	418	420	44	7192	-57.9%	+1.6%	2.0	85
Combination of: 4° BTDC Ignition 100°F Air Manifold Temp	10.63	2.08	.32	760	426	38	7572	-30.2%	+7.0%	3.1	11.4
4° BTDC Ignition 100°F Air Manifold Temp 182.1% Displacement Air	8.73	2.19	.31	549	395	32	7654	-42.7%	+8.1%	2.5	13.6
4° BTDC Ignition 100°F Air Manifold Temp 182.1% Displacement Air 8.2" Hg Exhaust Back Pressure	5.26	2.28	.40	332	412	41	8702	-65.5%	+22.9%	1.3	7.6

a) Base Conditions: Speed - 300 RPM   Air Flow Rate - 160% Displacement
               Power - 1080 BHP   Air Manifold Temp - 130°F
               Torque - 82.5 BMEP   Exhaust Back Pressure - 0" Hg
               Ignition - 10° BTDC

J-13

scme emissions reduction modifications, nor to what extent they were represen-
tative of the Basin population of such engines. Since the SCGC operated engines
emit only 20% of the total NOx emissions in the inventory, the higher EPA[23]
factor was applied, as was at the reduction potential suggested in ref. 23.
However, there remains considerable uncertainty at this time in the assessment
of reduction potential for this source category.

The options of exhaust gas treatment are likely to be more cost
effective for stationary internal combustion engines than for automobiles.
As discussed in Reference 23 this is due to effectiveness, ease of
installation and lack of cycling. Because of the fact that the catalytic
and thermal devices have no adverse effect on fuel economy the authors of
that report conclude that application of these devices is likely to be the
most effective. However, it appears that operational modifications alone
may prove to be cost effective also compared to current NOx reduction
programs discussed in Section 11.

CONCLUSIONS

Stationary IC engines constitute a significant source of NOx in
the South Coast Air Basin. On the basis of the engine census and EPA
emission factors, these engines contribute a total of 40 tons per day
of NOx. Results of tests by Cooper Bessemer and the Shell Development
Company[23] show significant NOx reductions with operational modifications
alone. This result is consistent with KVB test results which show large
decreases in NOx emissions as operating conditions were varied. Before
considering requirements for catalytic or thermal exhaust devices on these
engines a systematic investigation of NOx reduction through operational
modifications should be completed and the results evaluated.

References

23. "Stationary Internal Combustion Engines in the United States."
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33. Private Communication Elliott H. Harris, Southern California Gas
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35. Private Communication from Allan Muse, ARCO, November 1973, August 5, 1974.

36. Private Communication from F.A. Becker, Gulf Oil Company, November 7, 1973.

37. Private Communication from A.B. Hiser, Mobil Oil Company, March 21, 1974,
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38. Private Communication from H.M. Karr, Shell Oil Company,
    December 10, 1973, and July 1974.

39. Private Communication from Thron Riggs, Standard Oil, November 16, 1973,
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40. Private Communication from G.A. Collins, Jr., Texaco, November 29, 1973,
    July 1974.

41. Private Communication from D.H. Hanley, Union Oil Company, October 24, 1973,
    July 16, 1974.

66. Los Angeles County Air Pollution Control District Source Tests C1046,
    C1052, C1050, C1049, C1048, C1047, C1027, C1008, C1007, 1966-1967.